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Ms. Elizabeth O'Donnell, Executive Director
Kentucky Public Service Commission
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March 2, 2007

RE: ***An Exanimation of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company From November 1, 2004 to October 31, 2006* - Case No. 2006-00509**

Dear Ms. O'Donnell:

Enclosed please find an original and five (5) copies of Kentucky Utilities Company ("the Company") supplemental responses for Item No. 4 of the Commission Staff's Interrogatories and Requests for Production of Documents dated February 8, 2007, in the above-referenced proceeding.

Please contact me if you have any questions concerning this filing.

Sincerely,

Robert M. Conroy

Enclosures

cc: Michael L. Kurtz, Esq.
Elizabeth E. Blackford, Esq.

KENTUCKY UTILITIES COMPANY

March 2, 2007 Supplemental Response to Commission Staff's Interrogatories and Requests for Production of Documents Dated February 8, 2007

Case No. 2006-00509

Question No. 4

Witness: John P. Malloy

Q-4. Refer to Item 14, page 1 of KU's response to the Commission's December 18, 2006 Order. Explain whether KU has set any deadline for a decision concerning possible retirement of the mothballed Tyrone units.

A-4. Tyrone 1 and Tyrone 2 have been in service for 59 and 58 years, respectively. Prior to their dispatch in 2006, the last time that either of these units had operated was in 2001, when they ran for 143 and 133 service hours, respectively. Currently the Companies are performing a life assessment study on these units and a decision on retirement is expected by March 31, 2007. KU will supplement this response with the results of this study prior to the hearing.

On February 26, 2007 the Operating Committee ("OC") under the Power Supply System Agreement met to discuss the studies and reports concerning the possible retirement of Tyrone 1 and 2. At that meeting, the recommendations to retire Tyrone 1 and 2 were presented to and considered by the OC. Attachment 1 to this supplemental response contains the minutes of the February 26, 2007 OC meeting along with the presentation discussed at the meeting. Attachment 2 to this supplemental response contains the Company's Life Assessment Study for Tyrone Units 1 and 2. Attachment 3 to this supplemental response contains the Tyrone 1 & 2 Engineering Assessment and Analysis report prepared by Sargent & Lundy. Based on these analyses and the business judgment of the OC, Tyrone Units 1 & 2 were retired at midnight on February 26, 2007.

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Minutes of Operating Committee Meeting
February 26, 2007

Attendees: Members – Paul Thompson (Chairperson), Brad Rives (LG&E), John Voyles (LG&E), John Malloy (KU), and Scott Cooke (KU).
Others –Jason Knoy

Subject:
1. Appointment of Scott Cooke to the Operating Committee
2. Review and Approve Results of the Tyrone 1 & 2 Life Assessment Study

Meeting Summary:

Mr. Thompson opened the meeting at 9:00 A.M. with the appointment of Mr. Cooke to the Operating Committee.

Tyrone 1 & 2 Life Assessment Study
The life assessment study documents and associated presentation were previously provided to the Operating Committee for review. The results of the analysis were discussed. The units were mothballed on September 26, 2006 and require significant investment for their return to a condition that allows for reliable dispatch operation. It is not economic to invest the $16.1 million into the units to return them to service. Considering the units are nearly 60 years old, there is still the possibility that the units could fail even after refurbishment. Tyrone 1 and 2 are primarily used as reserve margin capacities because of the high cost to operate the units. Energy projections for the units through 2036 are less than 1100 MWh. There are no removal obligations that result from the retirement of Tyrone 1 and 2 due to Tyrone 3 still being operational. The recommendation was to immediately retire Tyrone 1 and 2. All Operating Committee members were in agreement with the recommendation.

The meeting was adjourned at 9:25 A.M.

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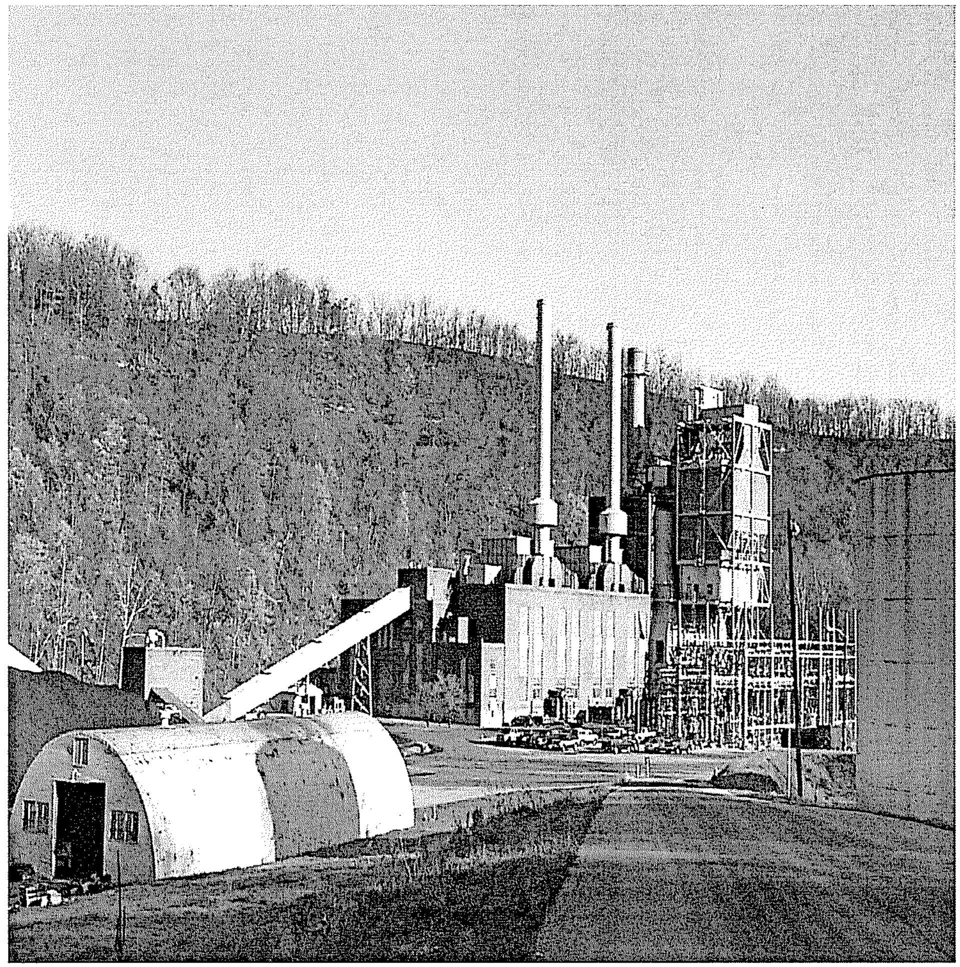
Tyrone 1 & 2 Life Assessment Study

February 26, 2007

Tyrone 1 & 2 Profile

- *Began operation in 1947*
- *30 MW generators*
- *Converted to fuel oil units in the 1970's*
- *Heat Rate – 18,000 BTU/kWh*
- *No generation output since 2001*



Reasons for Life Assessment Evaluation of Units

- Units "mothballed" since September 26, 2006 so they would not be considered for dispatch and to eliminate them from forced outage calculations
- Cost of repairing units as identified by Sargent & Lundy
- High Production Cost
- Lack of projected generation from the units leads the units to only be beneficial from a reserve margin perspective
- Increasingly stringent environmental regulations

Note: "Mothballed" is defined by IEEE 762 and GADS as "the State in which a unit is unavailable for service but can be brought back into service after some repairs with appropriate amount of notification, typically weeks or months."

Results of Analysis

- Sargent & Lundy (S&L) was contracted to assess the cost of returning the units to service
- Total costs to repair the units were estimated to be $16.1M
- Costs were divided in three categories: required, highly probable, and potential
- Case A compared the cost of $16.1M to repair the units against purchasing reserve margin purchases for June – September at $4/kw-month
- Case B compared the cost of $12.1M (only including required and highly probable costs) to repair the units against purchasing reserve margin purchases for June – September at $4/kw-month
- Case C compared the cost of $16.1M to repair the units against purchasing reserve margin purchases for June – September at $6/kw-month

Results of Analysis

Cases	Description	Benefit of Retirement to Net Present Value Revenue Requirements ($000s)
Case A	$16.1M* Cost Applied to Returning the Units to Service and Reserve Margin Price of $4/kw-month	$7,331
Case B	$12.1M** Cost Applied to Returning the Units to Service and Reserve Margin Price of $4/kw-month	$3,278
Case C	$16.1M* Cost Applied to Returning the Units to Service and Reserve Margin Price of $6/kw-month	$2,678

*$16.1M is inclusive of all required, highly probable, and potential costs identified by S&L to return the units to reliable status
**$12.1M is inclusive of all required and highly probable costs identified by S&L to return the units to reliable status

Other departmental impacts if Tyrone 1 & 2 are retired....

Utility Accounting & Reporting – No income statement impact. Tyrone 1 & 2 currently have a negative net book value, therefore there will be no impairment to the income statement if the units are retired. - Shannon Charnas

Corporate Finance – No financial impact from a bonds perspective due to no bonds outstanding on the units. - Dan Arbough

Rates & Regulatory – No regulatory approval required for retirement. – Robert Conroy

Recommendation

Based on this analysis, it is the recommendation of Generation Planning, in conjunction with Generation Engineering, that it is in the best interest of the Companies and the customers to retire units Tyrone 1 & 2 from service, effective February 26, 2007. The primary factors influencing this decision were the significant investment required for continued operation and the units' high cost of production.

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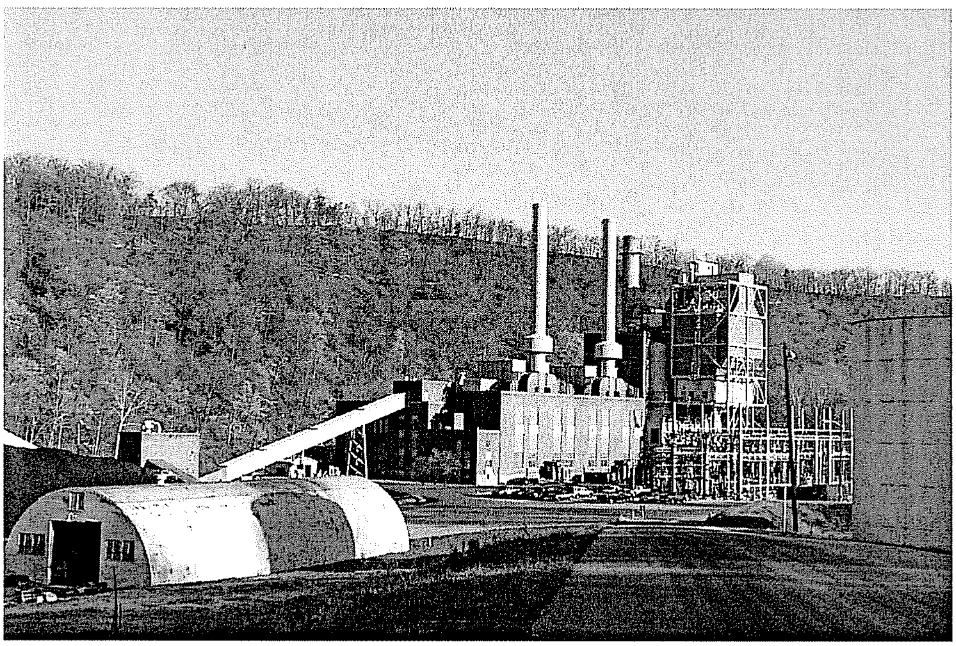
Generation Services

Life Assessment Study:
Kentucky Utilities
Tyrone Units 1 and 2



February 2007

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Life Assessment Study: Kentucky Utilities Tyrone Units 1 and 2

Executive Summary

Tyrone 1 & 2 were reported on forced outage on July 26, 2006, and were placed in "mothball" status on September 26, 2006. Event and performance data are submitted to the North American Electric Reliability Council (NERC) quarterly and updated continuously in the MicroGads Database on each Kentucky Utilities and Louisville Gas and Electric unit. It is optional, according to NERC and MicroGads standards, to place a unit that has been on forced outage for more than 60 days in mothball status while it is determined if the unit will be repaired for a return to service or retired. Placing a unit in mothball status eliminates the effect of the unit being out of service on a company's forced outage rate.

An engineering life assessment study was initiated, following Tyrone 1 & 2 being placed in mothball status, to determine if it was cost beneficial to return the units to service. Sargent & Lundy (S&L) was contracted to assess the condition of the units and provide technical comments and costs to return the units to service. Generation Services used the costs identified by S&L to analyze the effects of retiring verses returning the units to service on the net present value revenue requirements over a ten year study period. Revenue Requirements are the amount of money that must be paid or collected from customers to compensate a utility for all expenditures in capital, goods, and services. Therefore, this analysis determines the direct impact to the ratepayers if Tyrone 1 & 2 are returned to service or retired.

The major cost associated with retiring the units are reserve margin purchases required in the absence of the capacity of Tyrone 1 & 2. Reserve margin purchases will need to be made to comply with the 14% reserve margin capacity target listed in the latest Integrated Resource Plan (IRP) filing in 2005. A 14% reserve margin implies that our combined companies have access to capacity 14% above the peak load in order to assure reliability. This can either be met by building extra capacity or purchasing reserve margin purchases. The major savings associated with retiring the units include the avoided cost to refurbish the units to a reliable status as identified by S&L, annual depreciation expense, labor expense to operate and maintain the units, operation and maintenance expenses to keep the units at a reliable state, air and water fees, and an annual insurance premium.

In an analysis that included the required, highly probable, and potential costs identified by S&L, there was a benefit to the net present value revenue requirements of $7.3 million when the units are retired compared to being refurbished. Multiple sensitivities were evaluated to determine the validity of the initial result. These sensitivities included looking at the generation levels and associated costs and savings with an oil price decrease, a market price increase, and a combination of the oil price decrease and market price increase. Also evaluated were cases which included only the required and highly probable expenses identified by S&L and a reserve margin cost of $6/kilowatt-month figure instead of the $4/kilowatt-month used in the latest business plan. Each of these sensitivities showed that there was still a benefit to the net present value requirements if the units were retired.

A 30 year analysis, included in the appendix, was also evaluated to determine if there were any long term effects to the expansion plan if the units were retired. The retirement of Tyrone 1 & 2 resulted in units being installed at earlier dates than in the case with Tyrone 1 & 2 in service. The accelerated units in the expansion plan resulted in capital costs being experienced earlier, but also resulted in revenues from off-system sales and benefits from the fleet of units being more efficient from those units being in place earlier. Over the 30 year period, the retirement of Tyrone 1 & 2 led to an expansion plan that was more expensive inclusive of capital and operation and maintenance costs. However, even with this cost included in the analysis, over a 30 year period, it is still beneficial to retire Tyrone 1 & 2. The benefit to the 30 year net present value revenue requirements from retirement is $800,000. Therefore, it is the recommendation of Generation Services that Tyrone 1 & 2 be retired, effective immediately.

1.0 Background

Tyrone 1 & 2 were reported on forced outage on July 26, 2006, and were placed in mothball status on September 26, 2006, consistent with NERC and MicroGads policies. An engineering life assessment study was initiated to determine if it was cost beneficial to return the units to service. Sargent & Lundy (S&L) was contracted to assess the condition of the units and provide technical comments and costs to return the units to service. Generation Services used the costs identified by S&L to analyze the effects on the net present value revenue requirements over a ten year study period to determine the impact the decision would have on the ratepayer.

1.1 Tyrone Units 1-2

Tyrone Generating Station is nearly 60 years old, built in 1947 on the Woodford County side of the Kentucky River between Versailles and Lawrenceburg. Groundbreaking occurred on December 12, 1945. Unit 1, a 30-megawatt generator, began operation in 1947. Unit 2, also a 30 megawatt generator, began operation in 1948. Units 1 and 2 were converted to No. 2 fuel oil in the 1970s, and they are currently used only when demand for electricity is unusually high.

Tyrone Units 1 and 2 consist of four Babcock & Wilcox, balanced draft, non-reheat, oil fired boilers supplying steam to a common header. Steam at 910 F, 850 psig, is supplied to two 30 MW Westinghouse steam turbines.

2.0 Economic Impact Evaluation

The major costs associated with retiring the units are reserve margin purchases required in the absence of the capacity of Tyrone 1 & 2 and the lost production from the units. The optimal target reserve margin, a certain level or guaranteed capacity above peak load levels, from the 2005 Integrated Resource Plan ("IRP") for the combined companies, KU and LG&E, is 12% to 14%, with the companies using a reserve margin target of 14%. This reserve margin target can be met by either building capacity or making reserve margin purchases. The value of the lost production is calculated by charging a fee of $100 per megawatt-hour to replace the expected generation with market purchases. The major savings associated with retiring the units include the avoided cost to refurbish the units to a reliable status as identified by S&L[1], annual depreciation expense, labor expense to operate and maintain the units, operation and maintenance expenses to keep the units at a reliable state, air and water fees, and an annual insurance premium. The effect of these items on the net present value revenue requirements were analyzed over a ten year study period to determine the direct impact on the ratepayer.

[1] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 1-2, page 11

Listed below are some key assumptions that were made in this analysis.

Base Key Assumptions:

- Off-System sales values in accordance with the current Generation/Off-System Sales forecast
- Forward Price Curve as in the 2006 Operating Plan
- Fuel forecast as in the 2006 Operating Plan
- No capacity value assigned to replace the loss of the units in the ten year analysis
- No employee severance cost or employee salary expenses avoided if unit not returned to service
- Retirement in-place can occur with no significant physical asset related cost
- SO_2 and NOx allowance pricing as in the 2006 Operating Plan
- Total cost of $4,360,000[2], as identified by third party contractor Sargent & Lundy, for required activities needing completion before returning the unit to service
- Total cost of $7,750,000[3], as identified by third party contractor Sargent & Lundy, for high probability activities needing completion before returning the unit to service
- Total cost of $4,035,000[4], as identified by third party contractor Sargent & Lundy, for potential activities needing completion before returning the unit to service

Table -1

Cases	Description	Benefit of Retirement to Net Present Value Revenue Requirements ($000s)
Case A	$16.1M* Cost Applied to Returning the Units to Service and Reserve Margin Price of $4/kw-month	$7,331
Case B	$12.1M** Cost Applied to Returning the Units to Service and Reserve Margin Price of $4/kw-month	$3,278
Case C	$16.1M* Cost Applied to Returning the Units to Service and Reserve Margin Price of $6/kw-month	$2,678

*$16.1M is inclusive of all required, highly probable, and potential costs identified by S&L to return the units to reliable status
**$12.1M is inclusive of all required and highly probable costs identified by S&L to return the units to reliable status

The effect on the net present value revenue requirements for case A is included in Appendix A. In this analysis, there was no capacity replacement associated with the retirement of the units. However, there was a $100 per MWh cost associated with purchasing power to replace the lost production. The only costs associated with retiring Tyrone 1 & 2 were the value of the lost

[2] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 6-1, page 51
[3] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 6-2, page 52
[4] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 6-3, page 52

production from the units and reserve margin purchases due to the capacity loss. Savings associated with retirement included: avoided cost to repair, depreciation expense avoided, operation and maintenance expenses avoided, air and water fees avoided, and an annual insurance premium for the newly added assets purchased to return the unit to service. The cost to repair the units is inclusive of all required, high probability, and potential activities identified by S&L. The benefit to the net present value revenue requirements from retiring the units in Case A is $7.3 million.

Tyrone 1 & 2 are oil fired units. Price sensitivities of lowering the cost of oil and raising market prices were evaluated to test the effect on the net present value revenue requirements from retiring Tyrone 1 & 2. These changes made no effect to the generation levels of Tyrone 1 & 2 and therefore did not change the result of the benefit to the net present value revenue requirements from retiring the units as identified in the base case of assumptions, or Case A.

The analysis performed in Case A assumes that all required, highly probable, and potential costs identified by S&L must be incurred for the units to operate reliably. However, if only the required and highly probable costs are incurred, there is still a benefit to the net present value revenue requirements associated with retiring Tyrone 1 & 2. This benefit is $3.3 million, as shown in the appendix as "Case B".

The last analysis evaluated was a scenario where all costs identified by S&L are incurred in returning the units to service and the cost for reserve margin purchases is increased to $6/kilowatt-month. This scenario, identified as "Case C", yielded a benefit to the net present value revenue requirements from retiring the units of $2.7 million. The reserve margin purchases would need to exceed $7.80/kilowatt-month to make it cost beneficial to retire Tyrone 1 & 2.

2.1 Expansion Plan Impact

Retiring Tyrone 1 & 2 will have an impact to the combined companies' current expansion plan. The retirement of the units would cause some of the current expansion units to be accelerated to cover for the lost capacity. Please see Table – 2 below for a comparison of the expansion plans. Over the course of the 10 year study period, this causes no effect to the net present value revenue requirements because no units are altered from the base case throughout the 2007-2016 time frame. Over a 30 year period, the accelerated units in the expansion plan resulted in capital costs being experienced earlier, but also resulted in revenues from off-system sales and benefits from the fleet of units being more efficient from those units being in place earlier. However, even with this cost included in the analysis, it is still beneficial to retire Tyrone 1 & 2. The benefit of retirement to the 30 year net present value revenue requirements is $800,000.

Table – 2

	Base Case	No Tyrone 1&2
2007		
2008		
2009		
2010		
2011		
2012		
2013	LGSC	LGSC
2014		
2015		
2016	SCCT	SCCT
2017	SCCT	SCCT
2018		CCCT
2019	CCCT	
2020		
2021		
2022	CCCT	CCCT
2023		
2024		
2025		LGSC
2026	LGSC	
2027		
2028		
2029		
2030		
2031	SCCT	SCCT
2032	LGSC	LGSC
2033		
2034		
2035		
2036		

SCCT is a 148 MW CT
CCCT is a 484 MW combined cycle
LGSC is a 739 MW coal unit

2.2 Reserve Margin Impact

The optimal target reserve margin from the 2005 Integrated Resource Plan ("IRP") for the combined companies, KU and LG&E, is 12% to 14%, with the companies using a reserve margin target of 14%. System reserve margin is expected to fall below 14% in the years of 2008-2012 without the retirement of Tyrone 1 & 2. This case is referred to as the "Base" in the following table. Based on 2006 unit ratings information and 2006 load forecast data, the system reserve margin is expected to be 15.4% in 2007, 12.6% in 2008, 10.0% in 2009, 13.8% in 2010, 11.9% in 2011, and 10.7% in 2012 with Tyrone 1 & 2 in service. If Tyrone 1 & 2 are retired at the end of this year, the 2007 reserve margin will be 14.6%. But load is expected to increase and the reserve margin will fall to 11.8% in 2008, to 9.2% in 2009, 13.0% in 2010, 11.1% in 2011, and 9.9% in 2012. The reserve margin increases to above 14% in 2013 with a new coal unit.

Additional reserve margin purchases will be needed in 2008-2012 if Tyrone 1 & 2 are retired. Despite the need for reserve margin purchases, the economic analysis results in an overall benefit to the net present value revenue requirement if the units are retired.

Table – 3

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Base	15.4%	12.6%	10.0%	13.8%	11.9%	10.7%	18.5%	17.0%	15.0%	15.4%
Tyrone 1&2 Retired	14.6%	11.8%	9.2%	13.0%	11.1%	9.9%	17.7%	16.3%	14.3%	14.7%

Purchases are budgeted to cover the amount of capacity needed to reach a 14% reserve margin. In order to maintain a 14% reserve margin, additional capacity must be purchased in 2008-2012 if Tyrone 1 & 2 are retired. These purchases would be required in the months of June through September when load reaches its peak for the combined companies. Upper limit projections estimate a capacity cost of $6 per kilowatt-month. In the latest budget plan, a cost of $4 per kilowatt-month is applied to reserve margin purchases. Therefore, the $4 per kilowatt-month is used in this study and an analysis showing the effects of a $6 per kilowatt-month is used to evaluate the effect on the net present value revenue requirements from retiring Tyrone 1 & 2 as well. The cost associated with these purchases is defined as Reserve Margin Purchases in the tables in the appendix.

2.3 Fuel Adjustment Clause Impact

Tyrone 1 & 2 are the highest cost units among the KU/LG&E fleet. The dispatch cost for Tyrone 1 & 2 has ranged from $200 per megawatt-hour to over $250 per megawatt-hour during 2006. The Fuel Adjustment Clause ("FAC") requirement on recoverable purchase power cost is that the cost has to be less than the highest cost unit. However, Tyrone 1 & 2 cannot be used as the highest cost unit since they are currently not available. [Note: These units had a forced outage that began on July 28, 2006. In alignment with NERC requirements, after 60 days the units were placed into mothball status. They will remain in mothball status until they are either place into active operation or are retired.

If Tyrone 1 & 2 are returned to service, there would be virtually no impact to the Fuel Adjustment Clause. Existing units, Haefling 1-3 are close to the cost of the Tyrone 1 & 2 units. The only way for the FAC to benefit from the return to service of Tyrone 1 & 2 is for the cost of the purchases to exceed the cost of the Haefling units. This is not likely to happen and therefore there would be minimal impact to the FAC filing if the units were returned to service.

2.4 Business Plan Impact

The current draft of the Business Plan excludes capital expenditures and O&M costs for Tyrone 1 & 2. Therefore, none of the costs identified by S&L are included in the current Business Plan. Incurring any of these costs would be in addition to our current plan. The projected cost, inclusive of all required, highly probable, and potential costs identified by S&L, to return the units to service is $16.1 million. The additional cost of yearly maintenance is projected to be around $20,000 per unit per year. In addition, if the units are projected to run, operational costs will need to be applied to the units. Based on projected generation, the operation dollars that will be spent on the units is projected to be approximately $11,000.

2.5 Off System Sales Impact

Tyrone 1 & 2 have not operated since 2001. Therefore, in the past five years the units have made no contribution to the Companies' off-systems sales levels. In the latest 30 year budget run, Tyrone 1 and Tyrone 2's generation is applied only to native load and is not allocated to off-system sales. From 2009 and beyond, the units are not forecast to run and are not expected to make any contribution to off-system sales.

2.6 Environmental/Emission Allowance Impact

Tyrone 1 & 2 are oil fired units. Therefore, they do not emit a significant amount of SO_2 as a part of the combustion process. They do emit a small amount of NOx when in operation.

Units that are retired retain future SO_2 allowances allocated to them. However, since Tyrone 1 & 2 did not receive SO_2 allowance allocations, the combined companies SO_2 allowances will not change if Tyrone 1 & 2 are retired.

Units that are retired retain the NOx allowances previously allocated to them, but generally do not receive future allocations. Tyrone 1 & 2 were not allocated any allowances for 2007-2008 due to lack of heat input. For 2009 and beyond, they are expected to receive no ozone-season allowances and no annual allowances under Kentucky's proposed regulations to implement CAIR due to their lack of heat input in recent years. Therefore, if Tyrone 1 & 2 are retired, there will be no effect on the amount of NOx allowances for the combined companies.

Since Tyrone 1 & 2 are not projected to run during the ozone season when they generate in 2007 and 2008, there would be no NOx emission cost savings from retiring the units.

2.7 Water Permit Impact

The USEPA granted Kentucky primacy to issue and enforce NPDES permits within the state; the existing Kentucky Pollution Discharge Elimination System (KPDES) permit for the Tyrone plant is required to describe water management processes including an estimate of daily flows. If Tyrone Units 1 & 2 are retired, there would be changes to the water intake system.

Assumed Relevant Physical Changes if Tyrone 1 & 2 are retired

- Continued (but decreased) use of the Units 1-2 service water pumps with intake through the existing Units 1-2 river intake/traveling screen structure;
- Unit 3 service and circulating pumps would continue to operate and be supplied from the Unit 3 river intake/traveling screen structure;

- Discontinued use of the Units 1-2 Circulating Water pumps.

The above mentioned changes would likely require a minor modification of the permit which would consist of a technical package submission describing any reconfigured flows and adjustments of the service and circulating water intake and discharge flow estimates. It is not expected that these changes would change existing KPDES permitted conditions or outfall limits.

Although the KPDES permit must describe if one or both river intakes are used, it will not significantly affect the permit conditions or limits if the plant continues to use one or both intakes. Future operations flexibility, or additional water intake needs, may be enhanced by continued use and maintenance of the Unit 1-2 river intake structure.

2.8 Insurance Impact

Currently there is not insurance coverage for Tyrone 1 & 2. If the units are returned to service, the insurance premium would be $.06 per $100 of the insured assets value. Typically, the full replacement cost of the asset is insured. Therefore, for the net present value revenue requirements analysis, the assumed insurance premium is 0.06% of the projected cost for repairs.

2.9 Depreciation and Net Book Value Remaining at Retirement Impact

Based on the past practices of the utilities, if Tyrone 1 & 2 are retired, the net book value of -$783,850 as of June 30, 2006 would remain unchanged unless there were removal costs associated with retiring the unit. If so, the net book value for the unit would move closer to zero. However, it is suspected that there will be no removal costs associated with Tyrone 1 & 2 if the units are retired in the near future. The units and their assets are expected to be abandoned in place. The land at the Tyrone station is a common asset between all three units and has a net book value, $52,070 as of June 30, 2006. This value would remain unchanged by the retirement of Tyrone 1 & 2. Depreciation is not calculated on assets that are retired. Therefore, if Tyrone 1 & 2 are retired, the yearly depreciation expense of $12,000 will be avoided.

2.10 Human Resources Impact

Currently there are no employees dedicated to the operation of Tyrone 1 & 2. All of the employees at the Tyrone Station work under a budget for Tyrone 3. Retirement of Tyrone 1 & 2 would result in no headcount reduction therefore no severance pay expense or savings associated with headcount at the Tyrone Station would be expected.

If Tyrone 1 & 2 were returned to service, employees would need to be trained on how to operate the units. This cost is estimated by S&L to be $300,000[5]. Also, existing staff would need to work 8 hours per week on preventative maintenance for the units on overtime or double-time

[5] "Engineering Assessment and Analysis of Tyrone 1 & 2", Sargent & Lundy, Table 5-1, page 50

hours depending on the day of the week when the units are in operation. The labor expense associated with Tyrone 1 & 2's return to service is included in the net present value revenue requirements analysis.

3.0 Regulatory Assessment

In the review of the Companies' 2005 IRP, the Kentucky Public Service Commission ("KPSC") has recommended that decisions to retire any generating unit(s) should be supported by a feasibility study regarding the decision to retire the unit(s) and that those studies should be included in the next IRP (which will be filed in 2008). Generation Planning full accepts the KPSC's recommendation and will include the appropriate documents with the 2008 IRP. However, approval from the KPSC is not needed to retire the units. Any aspect of retirement that might impact rates and the accounting for the retirement will be addressed in the next rate case.

3.1 SPCC Impacts

The Federal Oil Pollution Act requires that facilities storing more than 1320 gallons of oil maintain a Spill Prevention Control and Countermeasures Plan. In July of 2002, the USEPA revised the SPCC Federal Amendments to require compliance for both oil storage and oil-containing equipment. Retirement of the Units 1 and 2 does not significantly affect costs for site compliance except that significantly less oil must be stored on-site because only Unit 3 startup oil must be supplied. Without retirement of the units, improvements to berm of the existing 500,000 gallon tank, overfill protection equipment, and replacement of the underground lines from the tank to the building would be required. The tank may require repairs. With retirement of the units, the tank may be removed and replaced with a much smaller tank adjacent to the building. A new, smaller tank would reduce the company's environmental exposure.

3.2 316(b) Impacts

Revisions of Section 316(b) of the Clean Water Act require the company to demonstrate reductions of the impact of river water intake structures regarding fish impingement mortality. The retirement of Units 1-2 and reduction in water intake from discontinued use of the circulating water pumps reduces the total impact to fish impingement mortality of the Tyrone plant. Environmental Affairs has the responsibility to report the required reductions necessary for the facility through a reduction in flow; or alternatively, we must propose to install alternative technologies to reduce the impingement impacts. Retirement of the units will greatly contribute to meeting the regulatory reduction criteria and thus reduce (but not eliminate) additional capital investments required.

4.0 Safety Issues

Currently there is asbestos insulation on the turbines, boilers, and piping on Tyrone 1 & 2. In the event of a boiler tube leak or boiler 'puff' asbestos insulation on the boiler could be damaged and released into the building, exposing employees. The age of the boiler increases the risk of boiler tube leaks that could damage asbestos insulation. If the units are re-powered, boiler repair work and replacement of boiler controls will reduce, but not eliminate the risk of asbestos release. If the unit is retired there will be no risk of boiler pressurization or steam release to destroy the asbestos and transport it throughout the building. The asbestos insulation will remain encapsulated.

Mercury is present in some of the boiler controls, adjacent to live steam lines. In the event of a rupture of the steam line within the controls, mercury would be vaporized and into the atmosphere in the plant. Staff would be exposed and mercury cleanup procedures would be required. This risk would be eliminated by retiring the units, or replacing the controls if the units are re-powered.

Due to the vintage of the units it is expected that some if not all paint used for the units is lead based. For Tyrone Units 1 & 2 to continue safe operation, minimizing the abovementioned safety risks, the equipment maintenance describe in the S&L Life Assessment report would be required.

5.0 Conclusions and Recommendations

The economic analysis performed in this study, supported by the S&L Life Assessment Study, concludes it is in the best interest of the Companies and the ratepayers to retire Tyrone Units 1 and 2 from service. The primary factors influencing this decision were the significant investment required for continued operation and the units' high cost of production.

Appendix
Case A
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Base Scenario - Purchase Market at $100 per MWh

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Yr NPVRR @ 7.61%
Retirement Costs											
Lost Production*	$74	$11	$0	$0	$0	$0	$0	$0	$0	$0	$85
Reserve Margin Purchases	$0	$2,601	$2,601	$1,121	$2,601	$2,601	$0	$0	$0	$0	$9,306
Total NPV Revenue Requirements Costs from Retirement											$9,391
Retirement Savings											
Total Cost to Repair	$16,145	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,145
Depreciation Avoided	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$88
Labor Expense	$11	$11	$11	$11	$12	$12	$12	$12	$13	$13	$86
Operation and Maintenance	$49	$42	$42	$42	$43	$44	$45	$46	$47	$47	$327
Air/Water Fees	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$4
Insurance Premium	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$71
Total NPV Revenue Requirements Savings from Retirement											$16,722
NPV Revenue Requirement Benefit of Retirement ($000)											$ 7,331

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

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Generation Services

Case B - Required and Highly Probably Costs Only
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Base Scenario - Purchase Market at $100 per MWh

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Yr NPVRR @ 7.61%
Retirement Costs											
Lost Production*	$74	$11	$0	$0	$0	$0	$0	$0	$0	$0	$85
Reserve Margin Purchases	$0	$2,601	$2,601	$1,121	$2,601	$2,601	$0	$0	$0	$0	$9,306
Total NPV Revenue Requirements Costs from Retirement											$9,391
Retirement Savings											
Total Cost to Repair	$12,110	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,110
Depreciation Avoided	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$88
Labor Expense	$11	$11	$11	$11	$12	$12	$12	$12	$13	$13	$86
Operation and Maintenance	$49	$42	$42	$42	$43	$44	$45	$46	$47	$47	$327
Air/Water Fees	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$4
Insurance Premium	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$53
Total NPV Revenue Requirements Savings from Retirement											$12,669
NPV Revenue Requirement Benefit of Retirement ($000)											$ 3,278

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

E.ON U.S.

Generation Services

Case C - All Costs and Reserve Margin Prices at $6/kw-month
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

Base Scenario - Purchase Market at $100 per MWh

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Yr NPVRR @ 7.61%
Retirement Costs											
Lost Production*	$74	$11	$0	$0	$0	$0	$0	$0	$0	$0	$85
Reserve Margin Purchases	$0	$3,902	$3,902	$1,682	$3,902	$3,902	$0	$0	$0	$0	$13,960
Total NPV Revenue Requirements Costs from Retirement											$14,044
Retirement Savings											
Total Cost to Repair	$16,145	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,145
Depreciation Avoided	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$88
Labor Expense	$11	$11	$11	$11	$12	$12	$12	$12	$13	$13	$86
Operation and Maintenance	$49	$42	$42	$42	$43	$44	$45	$46	$47	$47	$327
Air/Water Fees	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$4
Insurance Premium	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10	$71
Total NPV Revenue Requirements Savings from Retirement											$16,722
NPV Revenue Requirement Benefit of Retirement ($000)											$ 2,678

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

E.ON U.S.

Generation Services

Expansion Plan Analysis
Incremental Value of Retiring Tyrone 1 & 2
Net Present Value Revenue Requirements Analysis

(All dollars are in $000s)

		30 Yr NPVRR @ 7.61%
NPV Revenue Requirements Costs from Retirement		
	Reserve Margin Purchases	$9,306
	Expansion Plan Impact (Capital, O&M, OSS, Lost Production*)	$7,663
	Total	$16,969
NPV Revenue Requirements Savings from Retirement		
	Total Cost to Repair	$16,188
	Depreciation Avoided	$151
	Labor Expense	$164
	Operation and Maintenance	$617
	Emission Costs (SO2 and NOx)	$499
	Air/Water Fees	$8
	Insurance Premium	$122
	Total	$17,749
NPV Revenue Requirement Benefit of Retirement ($000)		$ 779

*Note: Tyrone 1 & 2 would not be dispatched during these hours in reality. This lost generation is representative of hours the units are forced to run in our generation model due to the constraints placed on the market purchase units and the time of dispatch being during maintenance season. In reality, these megawatt-hours would have been purchased from the market.

Tyrone 1 & 2
Engineering Assessment and Analysis

Prepared for
E.ON U.S. Services Inc.

Report SL-008956

e·on | U.S.

Project 12084-001
January 2007

Prepared by

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Final Report

Tyrone 1 & 2
Engineering Assessment and Analysis

Prepared for
E.ON U.S. Services Inc.

SL-008956
January 2007

Sargent & Lundy LLC
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LEGAL NOTICE

This report was prepared by Sargent & Lundy, L.L.C., hereafter referred to as Sargent & Lundy or S&L, expressly for E.ON U.S. Services, Inc. after referred to as E.ON US, in accordance with the service agreement authorizing this study. Neither Sargent & Lundy nor any person acting on their behalf (a) makes any warranty, express or implied, with respect to the use of any information or methods disclosed in this report or (b) assumes any liability with respect to the use of any information or methods disclosed in this report.

ENGINEERING ASSESSMENT AND ANALYSIS OF TYRONE 1 & 2

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ACRONYMS AND ABBREVIATIONS

Term	Description or Clarification
CPU	Central processing unit
ECT	Eddy current testing
ELCID	Electromagnetic core imperfection detection
EMAT	Electromagnetic acoustic transducer based testing
FAC	Flow assisted corrosion
GADS	Generating Availability Data System
I&C	Instrumentation and control
ID	Induced draft
MCC	Motor control center
MPI	Magnetic particle inspection
MPT	Magnetic particle testing
NDE	Non-destructive examination
NERC	North American Electric Reliability Council
NFPA	National Fire Protection Association
OEM	Original equipment manufacturer
pf	Power factor
PLC	Programmable logic controller
psi	Pound(s) per square inch
UT	Ultrasonic testing

1. EXECUTIVE SUMMARY

Sargent & Lundy, L.L.C. (S&L) was retained by E.ON U.S. Services, Inc. (E.ON US) to perform an engineering life assessment of Tyrone Units 1 and 2 to determine the capability of achieving the following levels of performance and reliability (Performance Targets) specified by E.ON US:

Table 1-1 — Performance Targets

Parameter	Unit 1	Unit 2
Capacity - Summer Net MW - Winter Net MW	31 33	31 33
Heat Rate, Btu/kWh	18,000	18,000
Forced Outage rate, %	6%	6%
Availability, %	94%	94%
Cold Start Duration, minutes	300	300

Tyrone Generating Station is located on the east side of the Kentucky River in Woodford County between the cities of Versailles and Lawrenceburg. Unit 1 and Unit 2 are each 30-MW electric generating units that began commercial operation in 1947 and 1948, respectively. Each unit has two steam boilers that supply steam to a Westinghouse steam turbine-generator. Units 1 and 2 share a common building with Unit 3, which is a 75-MW coal-fired unit that began commercial operation in 1953.

The four Unit 1 and 2 boilers were originally designed to burn coal and were converted to burn No. 2 fuel oil in the 1970s. The higher fuel costs and lower thermal performance of Units 1 and 2 relative to the E.ON US and the regional generation fleet have resulted in these units being seldom dispatched for operations. The units have operated an average of about 40 hours per year since 1985 and neither unit has been operated since 2001.

S&L conducted visual inspections of Tyrone Units 1 and 2 on October 30, 2006, with document reviews and plant staff interviews completed on October 31. The inspections consisted of walk-downs throughout both units and the common facilities in the company of E.ON US engineering and plant staff. The scope of this study did not include internal visual inspections of any of the equipment.

The minimal levels of unit operation over the past 30 years have resulted in only a few overhauls of some of the major equipment. Preventive maintenance has been focused on health and safety and facility integrity issues and the common service water and auxiliary electrical systems used by Unit 3. The other mechanical and electrical equipment and instrumentation and control (I&C) systems on Unit 1 and 2 have not been operated and have had little or no maintenance performed on them since 2001.

S&L's evaluation of the condition of the equipment and the required upgrade and replacement costs were based on the following:

- S&L's extensive experience in assessing the condition of power plant equipment including steam units of similar vintage and design,
- Available plant equipment and design documents and operating and maintenance records,
- Observations from the unit inspection walk downs, and
- Interviews and discussion with E.ON US engineering and plant maintenance and operations staff.

The available information does not indicate that any of the plant equipment is inoperable. However, given the age of the equipment, the minimal levels of preventative maintenance, and the long period of time since these units were last operated, an attempt to restart these units without prior inspections and maintenance could result in component malfunctions and failures that may result in a long, protracted startup period with the potential for damage to major equipment.

S&L recommends that a restart program be developed and implemented in order to provide for safe and reliable operations. A restart program would be similar to the process used in starting and commissioning a new unit. The restart program would include inspection and routine preventive maintenance for all the mechanical, electrical, and I&C equipment and systems on Units 1 and 2. It would also include overhauls and upgrades necessary for safe operations and to provide the level of reliability and performance specified in the Performance Targets. This report provides an engineering assessment and estimates of expected and potential costs for completing the inspections and necessary maintenance work.

Table 1-2 summarizes the estimated costs for inspections, maintenance, overhauls, and equipment upgrades and replacements needed to support the restart efforts and the subsequent safe and reliable operation of the units.

Table 1-2 — Cost Summary by Category

Cost Category	Cost ($Million)
Required Activities	$4.36
High Probability Activities	$7.75
Potential Activities	$4.04
Total Potential Restart Cost	$16.15

These cost categories are defined as follow:

- **Required Activities.** Required to provide for safe operations and to achieve the Performance Targets.
- **High Probability Activities.** Probably will be required, subject to inspections and testing.
- **Potential Activities.** Possibly required, given the age and condition of the unit equipment.

The cost estimates were developed using cost information available to S&L from previous project capital cost estimates and other work experience of the S&L project team. These estimates are intended to provide high-level estimates of the aggregate costs that would likely be required to restart the units for purposes of resource planning evaluations. If E.ON US's economic analyses using these preliminary cost estimates indicate that restart of these units could be a cost-effective resource option, S&L recommends that more extensive condition assessment and upgrade planning be performed in order to support detailed cost analysis with vendor-supplied budgetary estimates for the identified work.

Last page of Section 1

2. INTRODUCTION

2.1 STUDY PURPOSE AND OBJECTIVES

Sargent & Lundy, L.L.C. (S&L) was retained by E.ON U.S. Services, Inc. (E.ON US) to perform an engineering life assessment of Tyrone Units 1 and 2 to determine the capability of achieving the levels of performance and reliability specified by E.ON US for these units.

The scope of work consisted of visual inspections, staff interviews, and document reviews to evaluate the overall condition of the oil-fired generating units and to assess the general condition of the following major equipment and systems:

- Oil-fired boilers and appurtenances, including burners, headers and piping.
- Steam turbine and appurtenances including lube oil and turbine oil systems.
- Water supply systems including pumps, motors, and piping.
- Electrical systems including power distribution, relay protection, transformers, control systems, and instrumentation.
- Turbine, boiler, and balance-of-plant control systems.

The assessment also considered unit equipment and system safety issues, including the cost impacts of asbestos and lead paint remediation.

This report is the deliverable for this study. It includes a description of the evaluations and findings, along with recommendations and cost estimates for repairs, upgrades, and equipment replacement required to achieve the Performance Targets identified in Table 1-1.

2.2 FACILITY DESCRIPTION AND HISTORY

Tyrone Generating Station is located on the east side of the Kentucky River in Woodford County, Kentucky between Versailles and Lawrenceburg. Unit 1 and Unit 2 are each 30-MW electric generating units that began commercial operation in 1947 and 1948, respectively. Each unit has two steam boilers that supply steam to a Westinghouse steam turbine-generator. Table 2-1 summarizes the design gross unit and net unit power outputs and the manufacturer's design ratings for the steam turbine and generator on both Units 1 and 2. The boilers were originally designed to burn coal and were converted to burn No. 2 fuel oil in the 1970s. Units 1 and 2 share a common building with Unit 3, which is a 75-MW coal-fired unit that began commercial operation in 1953.

Table 2-1 — Units 1 and 2 Design Electrical Output and Turbine-Generator Ratings

Gross Unit Power Output	31.3 MW*
Net Unit Power Output	29.5 kW*
Nominal Steam Turbine Rating	25 MW**
Nominal Generator Rating	39.1 MVA**

* Performance Diagram, 1945 Forecast, Sargent & Lundy.

** "Steam Turbine Instructions", Westinghouse Instruction Book SO SA-5516.

The exhaust steam from the steam turbine is condensed in a surface condenser with once-through cooling water from the Kentucky River. The intake structure for Units 1 and 2 has two bays of traveling screens that supply the circulating water to Units 1 and 2 as well as service water to all three units.

The higher relative fuel costs and thermal performance of Units 1 and 2 has resulted in these units being seldom dispatched for operations. Information pertaining to the hours of operation of these units for the period January 1985 – December 2006 is summarized below. Neither unit has operated since 2001.

Table 2-2 — Summary of 1985–2006 Operations

1985-2006 Operations	Unit 1	Unit 2
Cumulative Hours	921	979
Average Annual Hours	42	45
Years with Zero Hours of Operation	9	10

Last page of Section 2.

3. FACILITY ASSESSMENT

3.1 PERFORMANCE TARGETS

The engineering assessment was based on achieving the following Performance Target values specified by E.ON US:

Table 3-1 — Performance Targets

Parameter	Unit 1	Unit 2
Capacity - Summer Net MW	31	31
- Winter Net MW	33	33
Net Heat Rate (Btu/kWh)	18,000	18,000
Forced Outage Rate	6%	6%
Equivalent Availability Factor	94%	94%
Cold Startup Duration (minutes)	300	300

S&L reviewed the available historical operating data and concluded that the targets for capacity and heat rate were consistent with the actual values from the limited operations since 1985. The level of maintenance and upgrade work outlined in this study would maintain and may even improve on these historical levels, as well as provide a high level of certainty in meeting the specified availability criteria and startup times.

3.2 TYRONE 1 & 2 INSPECTION AND REVIEWS

S&L conducted visual inspections of Tyrone Units 1 and 2 on October 30, 2006, with follow-on document reviews and plant staff interviews completed on October 31. The inspections consisted of walk-downs throughout both units and the common facilities in the company of E.ON US engineering and plant staff. The scope of this study did not include internal visual inspections of any of the equipment.

Overhauls of the major equipment have been infrequent over the past 30 years due to the minimal level of unit operations. Preventive maintenance has been focused on health and safety and facility integrity issues and the common service water and auxiliary electrical systems used by Unit 3. The low level of operations and associated required maintenance has not necessitated removal of the original asbestos insulation, lead paint, or the mercury-containing instruments and switches from the units. Most of the boiler and steam piping insulation is the original asbestos-based material. It appears that this insulation has been properly maintained. S&L did not find any areas of exposed or frayed insulation. E.ON US stated that there has also been no program to replace the original lead-painted surfaces throughout the units. Pealing paint was observed on some of the piping and structural steel members, but there was no observed accumulation of paint chips on the floors or other horizontal surfaces.

Units 1 and 2 are enclosed in a common building with the Unit 3 coal-fired unit. The building has been maintained so that the boiler and turbine equipment have been protected from weathering. The boilers were drained and a dehumidification system was installed in 2001 and kept in service on all four boilers through 2005. The feedwater, condensate, and service water systems were laid-up wet. The mechanical and electrical equipment and the instrumentation and control (I&C) systems have not been operated since 2001, with the exception of Unit 1 and 2 service water and coal handling systems used for operations of Unit 3. The steam turbine-generators have not been run on turning gear for over 3 years.

S&L's evaluation of the condition of the equipment and the required maintenance, upgrade and replacement costs were based on the following:

- S&L's extensive experience in assessing the condition of power plant equipment, including steam units of similar vintage and design,
- Available plant equipment and design documents and operating and maintenance records,
- Observations from the unit inspection walk downs, and
- Interviews and discussion with E.ON US engineering and plant maintenance and operations staff.

The available information does not indicate that any of the plant equipment is inoperable. However, given the age of the equipment, the minimal levels of preventive maintenance, and the long period of time since these units were last operated, an attempt to restart these units without prior inspections and maintenance could result in component malfunctions and failures that may result in a long, protracted startup period with the potential for damage to major equipment.

S&L recommends that a restart program be developed and implemented in order to provide for safe and reliable operations in an economically viable manner. A restart program would be similar to the process used in starting and commissioning a new unit. The restart program would include inspection and routine preventive maintenance for all the mechanical, electrical, and I&C equipment and systems on Units 1 and 2. It would also include overhauls and upgrades necessary for safe operations and to provide the level of reliability and performance specified in the Performance Targets. This report provides an engineering assessment and estimates of expected and potential costs for completing the inspections and necessary maintenance work.

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4. RESTART PROGRAM SCOPE AND COSTS

This section describes the specific equipment and system inspection, overhaul, and replacement work that will likely be required to successfully complete a restart effort and to achieve the Performance Targets. Inspections, overhauls, and equipment replacement work and their associated estimated costs were divided into the following three categories:

- **Required Activities.** Required to provide for safe operations and to achieve the Performance Targets.
- **High Probability Activities.** Probably will be required, subject to inspections and testing.
- **Potential Activities.** Possibly required, given the age and condition of the unit equipment.

S&L developed cost estimates for each identified work task using available information from previous S&L capital cost estimates and other work experiences of the S&L project team. These cost estimates include equipment, material, and labor in current 2006 dollars. Costs include allowances for asbestos and lead removal and disposal for the inspection, repair, and replacement work.

The cost estimates were developed using cost information available to S&L from previous project capital cost estimates and other work experience of the S&L project team. These estimates are intended to provide high-level estimates of the aggregate costs that would likely be required to restart the units for purposes of resource planning evaluations. If E.ON US's economic analyses using these preliminary cost estimates indicate that restart of these units could be a cost-effective resource option, S&L recommends that more extensive condition assessment and upgrade planning be performed in order to support detailed cost analysis with vendor-supplied budgetary estimates for the identified work.

4.1 BOILER AND APPURTENANCES

4.1.1 Background

The Unit 1 and Unit 2 Babcock & Wilcox (B&W) non-reheat boilers are each rated at 150,000 lb/hr, 1,000 psig, and 910°F.[1] There are two boilers providing steam to a single steam turbine for each unit. The boilers were

[1] "Tyrone Power Station, Equipment Data, Units 1&2", Sargent & Lundy, SL-1226, December 23, 1953.

originally designed to fire coal and were converted to oil firing in the early 1970s. The boiler drums are a rolled-tube design. The superheater header does not have tube stubs; the tubes are rolled and flared in the header. Overhaul records were not available.

Availability statistics from the North American Electric Reliability Council–Generating Availability Data System (NERC-GADS) database indicates that the boiler accounts for 50% of the occurrences of the top 25 component outage/derating causes for plants in the 1-MW to 99-MW size range. Accordingly, the condition of the boiler and associated auxiliary equipment is a critical element in developing a plan to achieve the Performance Targets.

4.1.2 Return to Service

Before returning the boilers to service, the following are recommended:

- Internal visual inspection
- Non-destructive examination (NDE) that focuses on boiler components whose failure would affect the reliability and availability of the boiler. Components that comprise the pressure parts of the boiler are the main focus for NDE since the failure of one of these components would have the highest impact on the reliability and availability of the boiler. The following areas and type of NDE are recommended:
  - Drum fluorescent magnetic particle testing (MPT) of major welds, selected attachment welds, and at least 20% of the ligaments
  - Tube ultrasonic thickness testing (UT) where external erosion or corrosion are observed
  - UT of the leading-edge tube row of the superheater
  - Electromagnetic acoustic transducer based testing (EMAT) of approximately 20% of the riser tubes to evaluate under deposit corrosion, pitting, or hydrogen damage
  - UT of the first economizer tube row
  - Critical piping NDE
- Safety valves testing and recertification
- Hydrostatic test of boiler at 1.5 times the design pressure

There is no universally recognized definition of critical piping. However, systems that represent a potential hazard to personnel or have a major impact on unit operation, because of their function or because of their operating conditions, are often referred to as "critical" piping systems. Table 4-1 lists the critical systems considered and the recommended NDE.

Table 4-1 — Critical Piping Evaluation Matrix

Piping & Header Systems	System Critical to Unit Operation	System Critical to Unit Efficiency	Probable Failure Mechanisms	Typical Examination Specified	Primary Areas for Examination *
Main Steam	Yes	Yes	Creep, Fatigue	MT, Replica, UT	H, F, E, V, N, IWA
Feedwater	Yes	Yes	Fatigue, FAC	MT, UT	H, F, E, V, N,
Extraction Steam	No	Yes	Fatigue, FAC	MT, UT	H, F, E, V, N,
Heater Drains	No	Yes	Fatigue, FAC	MT, UT	F, E, V
High-Energy Drains	No	Yes	Fatigue, FAC	MT, UT	H, F, E, V, N,
Auxiliary Steam Systems	No	Yes	Fatigue	MT, UT	H, F, E, V, N

* H = High stress areas of system from stress analysis, F = fittings, E = elbows, V = valves, N = nozzle connections, IWA = Integral Welded Attachments.

The costs for the activities listed above are estimated to be at least $150,000 per unit.

4.1.3 Major Concerns

4.1.3.1 Steam Drum

The steam drum is the most expensive boiler component. The carbon steel drum is rarely subject to significant creep damage due to the relatively low operating temperature. Component wear is primarily due to internal metal loss due to corrosion, which can occur during extended outages and from acid attack, oxygen pitting, and chelant attack. Damage can also occur from mechanical and thermal stresses on the drum, which concentrate at nozzle and attachment welds. These stresses, most often associated with boilers that are cycled on and off, can result in crack development. Cyclic operation can lead to drum distortion, resulting in concentrated stresses at the major support welds, seam welds, and girth welds. Since inlet feedwater temperature is significantly lower than the drum temperature, the feedwater penetration area has the greatest stress potential. Unit 1 and Unit 2 boilers are rolled-tube design. A problem unique to steam drums with rolled tube seats is tube seat water seepage. Caustic embrittlement of the joint can occur if a leak is not repaired. In addition, the act of eliminating the tube seat leak by repeated tube rolling can overstress the drum shell between tube seats and lead to ligament cracking. Information provided by E.ON US indicated that oxygen pitting in the drums has been observed on both Units 1 and Unit 2.

Based on the vintage of the equipment, the existing oxygen pitting, and the historical caustic embrittlement susceptibility, there is a high probability that major repairs will be necessary. A cost of $100,000 is allocated for these repairs.

4.1.3.2 Tubes

Boiler tube failures are the industry-wide primary cause for forced outages. Water-cooled tubes include the economizer, boiler bank, and furnace. The convection pass sidewall and screen tubes may also be water-cooled. These tubes operate at or below saturation temperature and are not subject to significant creep. Damage to these tubes can occur from excessive deposition that leads to corrosion and hydrogen damage. Waterside corrosion fatigue is a serious boiler tube failure mechanism. The failures usually occur close to attachments such as buckstay welds or windbox attachment welds. The combination of thermal fatigue stresses and corrosion leads to cracking initiated on the inside diameter that is oriented along the tube axis. Corrosion-fatigue has been identified on older units, those with greater than 30 years operation, as the root cause mechanism of riser tube failure. Whether caused by chelant attack or corrosion fatigue, the failures tended to be catastrophic with a large piece of tube rupturing. Based on the vintage of the equipment, a cost of $100,000 was allocated for replacement of 25% of the riser tubes for each of the four boilers.

4.1.3.3 Superheater

A portion of superheater tubes were replaced on Unit 1 in 1996. The superheater header does not have tube stubs; the tubes are rolled and flared in the header. Spacing of the tubes was noted to be very close, which makes repairs difficult. Based on the vintage of the equipment, there is a high probability that major superheater repairs will be necessary. The estimated capital cost for superheater tube repairs is $75,000 per unit.

4.1.3.4 Chemical Cleaning

Considering the period of idleness, tube oxidation will most likely be excessive. After repairs and tube replacements, a chemical cleaning of each boiler will be required. The estimated expense of cleaning is $100,000 per boiler.

4.1.3.5 Air Preheater

Each unit has a tubular air heater. Based on the vintage of the equipment, there is a high probability that sections of tube replacement will be necessary. An estimated capital cost for replacement of 25% of the air preheater tubes is $50,000 per unit, including minor repairs of ductwork damage.

4.1.3.6 Feedwater Piping

Depending on the operating parameters of the feedwater system, the flow rates, and the piping geometry, the pipe may be prone to corrosion or flow-assisted corrosion (FAC). This is also referred to as erosion-corrosion. If susceptible, the pipe may lose material from internal surfaces near bends, pumps, injection points, and flow transitions. Ingress of air into the system can lead to corrosion and pitting. Out-of-service corrosion can occur if the boiler is idle for long periods. Based on the vintage of the equipment and the idle time, there is a high probability that sections of the feedwater piping will need to be replaced. The estimated capital cost for replacement of 200 feet and 20 elbows in the feedwater piping system is $50,000 per unit.

4.1.3.7 Attemperator

The attemperator is subject to failures associated with thermal fatigue cracking of its components and welds. Since it is in a closed loop of the boiler, failures may go undetected until overspray or pieces of the attemperator lead to other damage, such as superheater tube failures due to pluggage or tube metal overheating from nucleate boiling on the tube surfaces. Based on the age of the equipment and the length of time with no operation, there is a high probability that the attemperators will need to be replaced. The estimated capital cost for attemperator replacement is $25,000 per unit.

4.1.4 Summary

The potential costs for returning the boilers to service, including recommended and high probability items, are summarized in the table that follows. The estimated costs were increased by 10% to account for asbestos removal and disposal where indicated in the table below.

Table 4-2 — Estimated Costs for Returning the Boilers to Service

Activity	Action	Estimated Cost
Internal Visual Inspection; Non-Destructive Examination; Safety Valves Testing and Recertification; Hydrostatic Test of Boiler *	Required	Unit 1 $165,000 Unit 2 $165,000 Total $330,000
Steam Drum Repairs*	High Probability repairs required	Unit 1 $110,000 Unit 2 $110,000 Total $220,000

Activity	Action	Estimated Cost
Tube Replacements	High Probability replacements required	Unit 1 $110,000 Unit 2 $110,000 Total $220,000
Superheater Tube Repairs	High Probability repairs required	Unit 1 $75,000 Unit 2 $75,000 Total $150,000
Chemical Cleaning	Required	Unit 1 $100,000 Unit 2 $100,000 Total $200,000
Air Preheater Tube Replacement*	High Probability replacements required	Unit 1 $55,000 Unit 2 $55,000 Total $110,000
Feedwater Piping Replacements*	High Probability replacements required	Unit 1 $55,000 Unit 2 $55,000 Total $110,000
Attemperator Replacement*	High Probability replacements required	Unit 1 $30,000 Unit 2 $30,000 Total $60,000
Total of All Required and High Probably Items		Unit 1 $700,000 Unit 2 $700,000 $1,400,000

* Includes 10% cost adder for asbestos removal and disposal.

4.2 STEAM TURBINE AND APPURTENANCES

4.2.1 Background

The Unit 1 and 2 Westinghouse steam turbines are each nominally rated at 25 MW. The steam turbines are non-reheat with inlet steam conditions of 850 psig / 900°F and have one Curtis stage impulse row and 25 reaction rows of blading. The last rows of blades are attached to a separate disc, which is shrunk fit onto the rotor.

Available information indicates the last inspection for the steam turbines was conducted in 1977–1978. The steam turbines were last operated in 2001

4.2.2 Return to Service

Before returning the steam turbines to service, the following activities are recommended:

- Internal inspection
- Non-destructive examinations
  - Visual and fluorescent MPI of the rotor surface and UT/MPI/ECT of the rotor bore for surface and forging defects
  - Visual and MPI of cylinder casing and shell
  - Visual and MPI of throttle valve body
  - Visual of the blades
  - ECT of blade root fixings
- Remaining life assessment based on the NDE data. Calculations based on fracture mechanics predicts crack initiation and growth rates under cyclic loading (fatigue) and enables a prediction if a crack of a given size, as determined by NDE, will fail under a particular load and if flaws will propagate to failure within known time and operational factors.

The rotors of steam turbines are subject to life limitations due to creep and thermal fatigue. Creep occurs during steady-state operation due to the centrifugal stresses sustained at high temperature while thermal fatigue arises from cyclic thermal stresses set up during startup and shutdown. The most serious threat to the rotor arises from the possibility that, near the bore, creep cracks may initiate and grow to a size that could result in a brittle fracture of the rotor during a cold start. Initiation may be assisted by any pre-existing forging defects in the near-bore region, and growth may be assisted by fatigue due to the thermal and mechanical stresses applied during starting.

Creep cracking can also occur at blade root fixings leading eventually to the loss of blades and possibly substantial consequential damage to the turbine. Creep, thermal fatigue, and stress corrosion cracking can occur at other stress-concentrating features, such as balance holes and changes of section; the effect of any cracking at such features depends on the local stress levels.

The turbine lube oil and control oil systems will require inspection, cleaning, and repair. Recommended activities include mechanical cleaning of the turbine oil tank and cleaning of the turbine oil coolers on both the shell side and tube side. The coolers should be tested for tube leaks. The turbine oil reservoir of about 2,500 gallons must be tested and will likely need to be reconditioned or replaced.

Turbine lube oil piping should be examined internally to determine the extent of corrosion. Chemical or mechanical cleaning may be required, but at a minimum, the entire oil system will require a high-velocity flush.

Inspection and cleaning of the generator seal oil piping and detraining tanks is recommended. The hydrogen dryer desiccant should be replaced, and the hydrogen and carbon dioxide inventories must be replenished. A generator hydrogen leakage rate test (air test) should be performed before generator operation.

If the NDE data and remaining life assessment determine that the steam turbines are suitable for continued operation, it is recommended that, at a minimum, the labyrinth seals and inner gland seals be replaced. Seal replacement is recommended to reduce steam leakage and improve the heat rate.

The costs for the recommended activities before returning the steam turbines to service are listed in the following table.

Table 4-3 — Recommended Activity Costs for Returning the Steam Turbines to Service

Activity	Estimated Cost	
	Unit 1	**Unit 2**
Disassemble and Reassemble for Inspection	$180,000	$180,000
Non-Destructive Examination	$150,000	$150,000
Remaining Life Assessment	$50,000	$50,000
Seal Replacements	$40,000	$40,000
Reconditioning of the Lube Oil System	$40,000	$40,000
Replenish Inventory of Turbine Oil and Operating Gases	$40,000	$40,000
Subtotal	$500,000	$500,000
Total	$1,000,000	

4.2.3 Major Concerns

4.2.3.1 Rotor

Older rotor forgings suffered from 'segregation' problems, whereby inclusions and impurities in the steel clustered at the center. The center of the forging was machined out to remove these impurities leaving the rotor bore. The combination of thermal and centrifugal stresses during startup, and creep strain during relaxation at temperature and under steady-state operation, makes the rotor bore the most highly stressed area of a rotor.

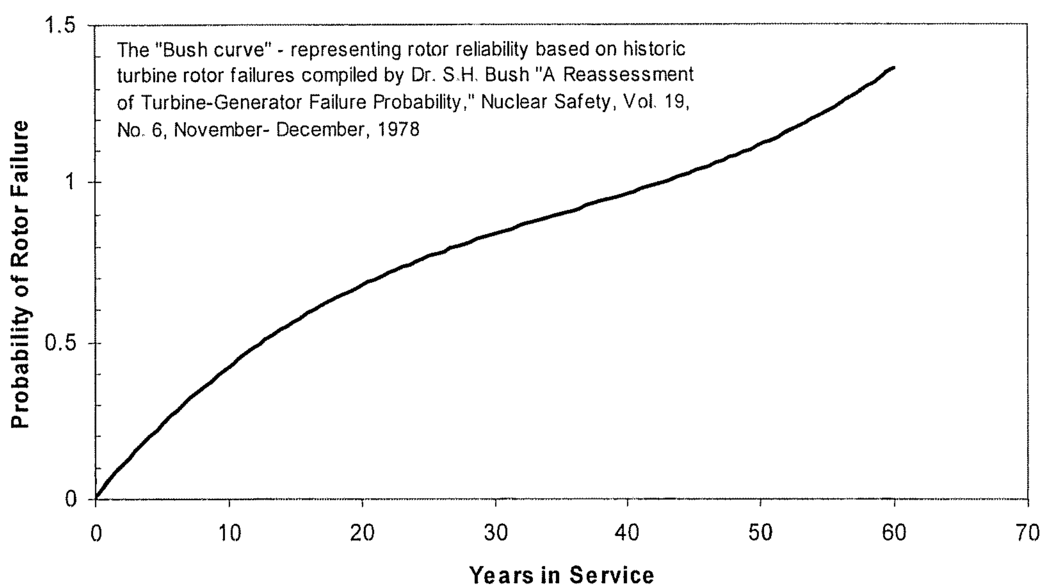
During a rapid cold start, the combination of high-periphery and low-bore temperature causes tensile thermal hoop stress at the bore. If the combined effect of thermal and centrifugal stresses during startup is sufficient, yielding occurs at the bore. As the rotor warms through, thermal stresses decrease, and the residual compressive stress (due to previous tensile yielding) reduces bore stress to less than the normal centrifugal stress. This reduction is compensated by increased stresses at larger radii in the rotor, which are redistributed by creep during operation. With sufficient operating duration, bore stress increases to the steady-state value with attendant accumulation of bore creep strain. Subsequent starts severe enough to cause bore yielding repeat the cycle, with each cycle increasing creep rate in the rotor body slightly until the equilibrium stress distribution is restored.

The most serious threat to a rotor from the bore region arises from the possibility that, near the bore, creep cracks may initiate and grow to a size that could result in a brittle fracture of the rotor during a cold start. Initiation may be assisted by any pre-existing forging defects in the near bore region, and growth may be assisted by fatigue due to the thermal and mechanical stresses mentioned above applied during startup and shutdown cycles.

In assessing critical crack size, it is assumed that an initial defect will be propagated by cyclic thermal and centrifugal stresses to a final size, beyond which catastrophic brittle fracture would occur. The critical size depends on stress level, the material's fracture appearance transition temperature (brittle-to-ductile transition), and temperature in the defect region. Again, for bore defects, the most arduous combination of these, as mentioned above, occurs during a cold start or overspeed test when thermal and centrifugal bore stresses are at their maximum, while the rotor bore temperature (and material toughness and resistance to brittle fracture) is low.

Regardless of the degree of sophistication employed in calculating or measuring stresses (or strains); there remains a considerable amount of uncertainty about their actual magnitude in service under different operating conditions. Similarly, one cannot assume a single value of strength (or strain capability). Heat-to-heat variations and even variations within a single large component, such as a rotor forging or turbine shell, introduce unavoidable uncertainties in material capability. Thus, it has become necessary to treat the problem statistically. The "permissible" probability of failure, or failure rate, depends on many factors, including the consequences of failure. While there is no definitive rotor end-of-life based on the number of service hours, the probability of rotor failure begins to increase significantly at 40 years of service, as depicted below. The graph in Figure 4-1 shows the probability of failure, expressed as percentage, as a function of years of operation. This curve was based on historic turbine rotor failures compiled by Dr. S. Bush. The Bush curve represents the cumulative hazard or probability of failure in percent versus operating time. The curve indicates that at 40 years in service the risk of rotor failure is 10 times greater than during the first couple of years in service.

Figure 4-1 — Probability of Turbine Rotor Failure versus Time



Since the rotor is the most expensive component of the steam turbine, failure will effectively be the end-of-life for the steam turbine. The installed replacement cost for a new rotor is estimated at $1,500,000. The risk of rotor failure estimated by NDE testing and remaining life assessment is as previously discussed.

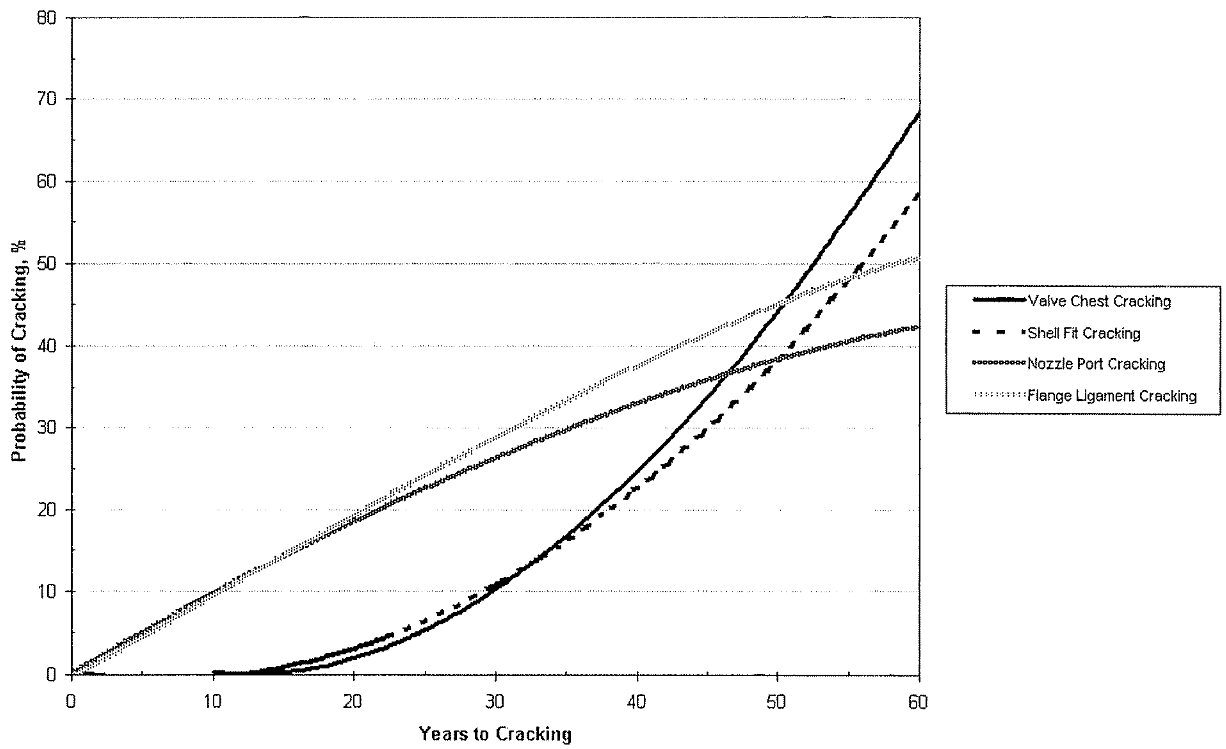
4.2.3.2 Shrunk on Disc

The last rows of blades are attached to a separate disc, which is shrunk fit onto the rotor. The keyways of the shrunk-on-disc design have high-stress concentrations and are susceptible to stress corrosion cracking. The tangential stresses are greatest at the keyways and steam has a tendency to condense in this area. Based on the vintage of the equipment, the inspection intervals, and the stress corrosion cracking susceptibility of the shrunk-on-disc design, there is a high probability that stress corrosion exists and major repairs will be necessary. For each steam turbine, the estimated cost of repairs is $200,000. Since the last rows of blades are attached to a separate disc, which is shrunk fit onto the rotor, the repairs would still be required if the rotor is replaced.

4.2.3.3 Steam Turbine Body

Valve chest, shell, nozzle ports, and flange ligament cracking can be expected as the units age, as depicted in Figure 4-2. The Unit 1 1961 inspection report indicated cracks were found in the high-pressure base and cover cylinders.

Figure 4-2 — Steam Turbine Body Cracking Probability



Based on the vintage of the equipment, the length of inspection intervals, and the historical cracking susceptibility, there is a high probability that stress corrosion exists and major repairs will be necessary. For each steam turbine, the estimated cost of repairs is $125,000.

4.2.3.4 Throttle Valve Body

Records indicate the Unit 1 throttle valve body was replaced in 1979. Radiographic tests revealed the valve body was honeycombed with stress and metal fatigue cracks, which made it unsafe to operate and unable to be repaired by welding. There is a high probability, based on the Unit 1 history, that the Unit 2 throttle valve body has stress and metal fatigue cracks that will necessitate replacement. The estimated cost for the Unit 2 throttle valve body replacement is $150,000.

4.2.3.5 Blades

There is no record of any blade replacements for the steam turbines. Due to the higher moisture content steam at the low-pressure section, trailing edge erosion is a high probability for at least the last three rows of blading. Replacement cost for the last three rows of blades for each steam turbine is estimated to be $200,000 per unit.

4.2.4 Summary

The potential costs for returning the steam turbines to service, including recommended and high probability items, are summarized below.

Table 4-4 — Estimated Costs for Returning the Steam Turbines to Service

Activity	Action	Estimated Cost
Disassemble and Reassemble for Inspection Non-Destructive Examination Remaining Life Assessment Reconditioning of the Lube Oil System Replenish Inventory of Turbine Oil and Operating Gases	Required	Unit 1 $460,000 Unit 2 $460,000 Total $920,000
Seal Replacements	Required if adequate remaining life remains	Unit 1 $40,000 Unit 2 $40,000 Total $70,000

Activity	Action	Estimated Cost
Rotor Replacement	Potential Activities - As determined by Remaining Life Assessment	Unit 1 $1,500,000 Unit 2 $1,500,000 Total $3,000,000
Shrunk-on-Disc Repairs	High Probability repairs required	Unit 1 $200,000 Unit 2 $200,000 Total $400,000
Steam Turbine Body Repairs	High Probability repairs required	Unit 1 $125,000 Unit 2 $125,000 Total $250,000
Throttle Valve Body Replacement*	High Probability Unit 2 replacement required	Unit 2 $165,000 Total $165,000
Blade Replacements	High Probability last 3 rows replacement required	Unit 1 $200,000 Unit 2 $200,000 Total $800,000
Total of All Required and High Probably Items		Unit 1 $1,025,000 Unit 2 $1,190,000 $2,215,000
Total if New Rotor Required		Unit 1 $2,525,000 Unit 2 $2,690,000 $5,215,000

* Includes 10% cost adder for asbestos removal and disposal.

4.3 WATER SYSTEMS

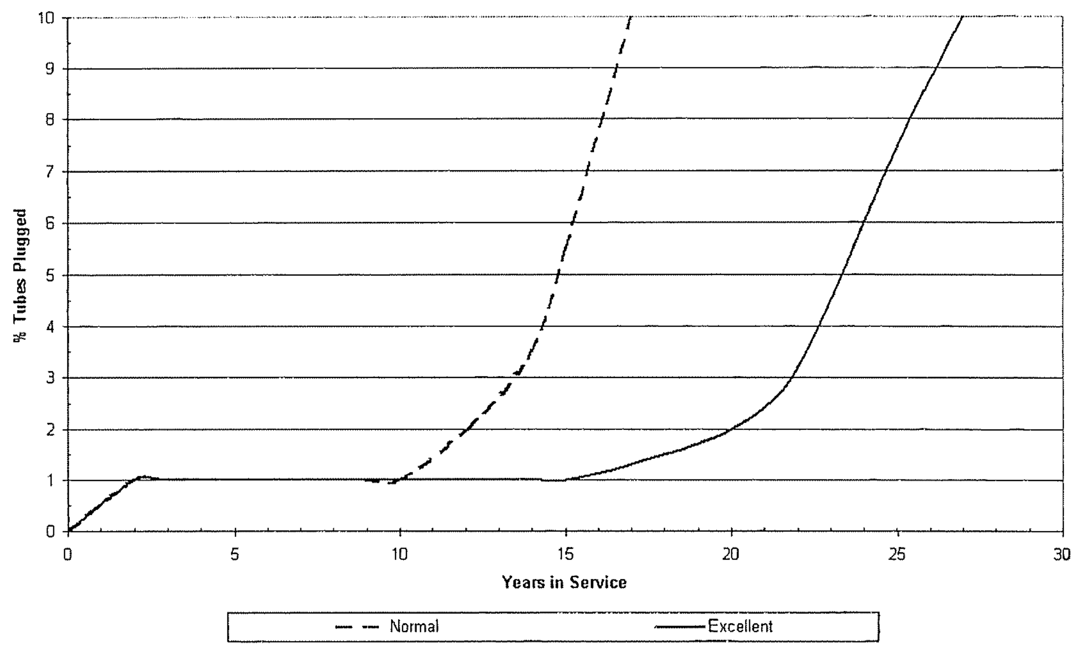
4.3.1 Feedwater Heaters

Each unit has two low-pressure and two high-pressure feedwater heaters, all manufactured by the American Locomotive Company. Low-pressure heater No. 1 has 600 Admiralty tubes, and No. 2 has 479 Admiralty tubes. High-pressure heaters No. 3 and No. 4 each have 384 copper nickel tubes. A detailed survey was conducted (*High-Reliability Feedwater Heater Study*, Palo Alto, California: Electric Power Research Institute, June 1988. CS-5856) to rate the problem areas in the feedwater heaters. The top problem areas are listed below:

- Normal and abnormal operating conditions — highest
- Tube plugging (leaks)
- Drain cooler zone level control
- Steam impingement desuperheat zone
- Tube vibration
- Steam impingement condensing zone
- Inlet end erosion
- Loss of impingement plates

Typically, plugged tubes do not become a concern with respect to thermal performance until the pluggage rate approaches 10%. This typically occurs after 15 to 25 years in service, as depicted in the following life cycle curve.

Figure 4-3 — Life Cycle of Heat Exchanger Tubing



Source: R. J. Bell and S. D. Strauss, "Advancing Heat Exchanger Reliability," *Power*, July 1991.

There is no record of any heater or heater tube replacements. Based on the vintage of the equipment, there is a high probability that feedwater heater tube replacements will be necessary to maintain the thermal efficiency of the units. E.ON US stated that the steam-side baffle plates have been damaged in all the heaters, which will require the replacement of these baffles. This work will require the entire tube bundles to be removed from the heater shell. With the heater bundles removed from the heater shells, the incremental cost of replacing all of the tubes is relatively low compared to selective tube replacements. The estimated cost of complete feedwater heater retubing and baffle replacements is $40,000 for each heater, for a total of $160,000 per unit.

Feedwater heater shell pressure relief valves should be replaced with factory-certified valves.

4.3.2 Feedwater Regulator Valves

The feedwater regulator (Bailey) valves are critical to drum level control. The valve trim may seize after extended idleness. The valves should be disassembled and inspected and then repaired and repacked. The estimated cost for valve refurbishment is $10,000 each.

4.3.3 Condenser

Each unit has a steam surface condenser containing 4,776 Admiralty tubes. There is no record of any tube replacements. As depicted in the preceding life cycle curve (Figure 4-3), tube pluggage rate affecting thermal performance typically occurs after 15 to 25 years in service. Based on the vintage of the equipment, there is a high probability that condenser tube replacements will be necessary to maintain thermal efficiency of the units. Typically, the condenser pressure is not significantly affected until the number of plugged tubes exceeds about 10% of the total. It appears that there is sufficient space between the condensers to allow for individual tube replacements. For each unit, S&L assumed that 25% of the tubes would be replaced at an estimated cost of $50,000 per unit.

If the tubes are not replaced, a condenser tube plug cleaning is recommended, followed by a steam space flooding to find tube leaks and plug defective tubes. The water box priming jets and the condenser steam space startup air ejector should be inspected and cleaned.

4.3.4 Circulating Water Intake and Piping

According the Tyrone Plant staff, the silt build-up at the river water intake has reduced the water withdrawal capacity by at least 50%. For Unit 1 and 2 to operate at full load, the intake area will need to be dredged. The estimated cost for the dredging and disposal of the spoils is $100,000. This assumes the Toxicity Characteristic Leachate Procedure determines that the spoils can be deposited on site.

The circulating water intake is a 72-inch pipe from the Kentucky River to the plant. There is no record of an inspection. Before return to service, an inspection of the intake piping is recommended. The estimated cost for inspection, excluding any necessary repairs, is $20,000.

Traveling screens at the circulating water intakes will require lubrication, and the backwash jets should be inspected and cleaned. Repair costs for these activities are estimated to be $10,000.

4.3.5 Service Water

The service water system piping, in particular the piping to supply bearing cooling water (filtered water) to the various plant rotating equipment, has reportedly been having plugging problems. Before return to service, an inspection of the service water system piping and strainers is recommended. The estimated cost for inspection and miscellaneous replacements is $25,000 per unit.

4.3.6 Summary

The potential costs for returning the water systems to service, including recommended and high probability items, are summarized below.

Table 4-5 —Estimated Costs for Returning the Water Systems to Service

Activity	Action	Estimated Cost
Circulating Water System	Required	$130,000
Service Water Piping	Required	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Feedwater Regulating Valve Reconditioning*	Required	Unit 1 $10,000 Unit 2 $10,000 Total $20,000
Feedwater Heater Tube Replacements*	High Probability	Unit 1 $175,000 Unit 2 $175,000 Total $350,000

Activity	Action	Estimated Cost
Condenser Tube Replacements	High Probability	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Total		$650,000

* Includes 10% cost adder for asbestos removal and disposal.

4.4 ELECTRICAL SYSTEMS

The main electrical power train of Tyrone consists of the 39,063-kVA generator delivering 13.8-kV power to generator step-up transformers in the open-air switchyard, where the voltage is increased to 69 kV for delivery to the grid. The switchyard has a 2,500-kVA reserve auxiliary transformer that is used for startup and as a backup to the 2,500-kVA main auxiliary transformers that are powered from the generator bus and used to supply the plant's 480-volt auxiliary motors and other 480-volt equipment. Underground cable connects the generator to the transformers in the switchyard.

4.4.1 Transformers and High-Voltage Circuit Breakers

4.4.1.1 Background

The original main generator step-up transformers were single phase with each phase sized for 12,500 kVA. In the early 1950s, a failure of one of the Unit 1 transformers resulted in its replacement by a three-phase transformer, which came from another plant. The "A" phase and "C" phase transformers were removed, but the "B" phase transformer was kept in place as a spare for Unit 2. The current arrangement of the transformers in the switchyard has the Unit 1, three-phase transformer at the north end of the yard. Next to it is the original Unit 1 "B" phase that is now an available spare for Unit 2 followed by the three-phase reserve transformer and the three single-phase main generator step-up transformers of Unit 2.

A 69-kV oil-filled circuit breaker is used to connect the main step-up transformers and the reserve auxiliary transformer to the 69-kV transmission system. The two auxiliary transformers are sitting just outside the boiler room with no fire walls or fire suppression system protecting the building adjacent to them.

Only the reserve auxiliary transformer is currently energized. It is being used to carry lighting services and some of the plant's other housekeeping loads in the buildings. The two de-energized unit auxiliaries are interconnected with the still-active Unit 3 through several 480-volt switchgear and motor control center (MCC) busses. This makes the reserve transformer a requirement for the still active unit.

Each of these main transformers is 60 years old, with the possible exception of the replacement transformer for Unit 1. This generator step-up transformer was not new when it was installed on Unit 1 and its exact age is not known, but it is likely that it is as old as or older than the other original transformers. Sixty years is well beyond the expected life of a power transformer, even with the light duty they were given over the past several years. In spite of the advanced age of the transformers, they could continue to be operated if they could be refurbished and tested out successfully.

4.4.1.2 Return to Service

The fact that the transformers have been de-energized and dormant for at least five years will require them to be completely checked out before they can be energized with any degree of confidence. The transformer oil will likely need to be reconditioned or replaced, as will the high-voltage circuit breaker oil. Bushing, gauges, and cabling on the equipment may also require replacement. Cabling, fans, and pumps will all likely require maintenance to get them into operating condition.

The transformers will also require a battery of insulation tests, starting with a basic megger test, as a prerequisite to other testing and to ensure there are no weak points that would cause the transformer to fail when energized. Other Doble or power factor testing, turns ratio testing, etc. will be needed to prove the transformer is in operable condition and can be energized safely.

4.4.1.3 Major Concerns

Each of the principal transformers and high-voltage circuit breakers identified above is critical to the operation of the unit to which it serves. A transformer or 69-kV breaker failure would result in a unit trip, which makes each of these transformers or oil-filled circuit breakers a critical item. The insulation systems deteriorate with age and the type of usage or loading the transformer has over its time in service.

From the testing of these transformers or breakers to bring them back into service, one could expect to find weak points in the insulation, the need to replace fans and coolers due to rusting and leakage at flanges, inter-turn shorts in the windings, and general deterioration of the transformer or breaker due to the effects of aging.

4.4.1.4 Summary

To put these transformers back into reliable service, the cost noted below may be incurred.

Table 4-6 — Estimated Costs for the Main and Auxiliary Transformers and High-Voltage Circuit Breakers

Activity	Action	Estimated Cost
Testing: Complete testing for power factor (pf), insulation resistance of windings and core, check bushings for pf and capacitance	Required	Unit 1 $25,000 Unit 2 $25,000
Oil Replacement: Replace or recondition oil in all transformers and oil filled breakers	Required	Unit 1 $25,000 Unit 2 $25,000
Equipment Replacement: New temperature devices, new bushings and fans on some transformers, new conservator tank for Unit 1 main power transformers	High Probability	Unit 1 $50,000 Unit 2 $30,000
Replace Unit 1 main power transformers and Unit 2 auxiliary transformer (Incremental of oil and equipment replacement costs)	High Probability	Unit 1 $370,000 Unit 2 $35,000
Replace Unit 2 main power transformer and Unit 1 auxiliary transformer (Incremental of oil and equipment replacement costs)	Potential	Unit 1 $35,000 Unit 2 $250,000
Total		$870,000

4.4.2 Generators

4.4.2.1 Background

Each unit has an identical hydrogen-cooled generator rated for 39,063 kVA at 30 psi of hydrogen. These generators have not been synchronized to the transmission system for several years, and they have not been inspected with the rotors out since the late 1970s. These old Westinghouse generators were quite hardy with a very simple excitation system that consisted of a small 2.5-kW dc pilot exciter feeding the field of a larger 125-kW dc main exciter. The main exciter's output to the generator's rotor windings is adjusted by a rheostat in its field circuit, which is controlled by a voltage regulator looking at generator output voltage. There is a spare exciter available on the turbine deck that can be used by any of the machines at the site.

4.4.2.2 Return to Service

The Rototrol Westinghouse excitation system will probably still be usable due to the simplicity of its design and equipment. Nevertheless, the insulation on the 60-year-old generator has lasted far beyond its expected life, which means the generator would not be considered reliable unless it were inspected and tested to show that it did not need to be rewound. Inspection and testing would have to be done to confirm this or to prove that the machine's condition is satisfactory enough to bring it back on line.

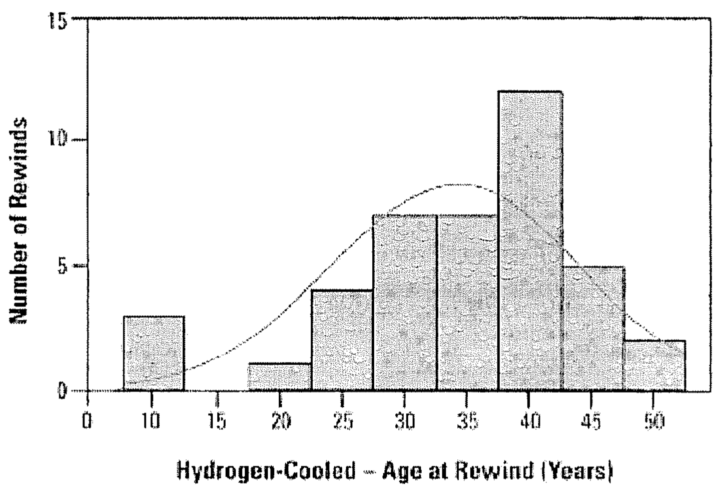
Older generators have other problems besides the aging of the insulation. Core distortion causing the laminated steel plates of the core to short and produce hot spots is also a likely possibility. Hydrogen seals at the generator bearings will need to be inspected and most likely repaired unless the generator is to be de-rated by eliminating the hydrogen and cooling the generator with air. This change would de-rate the unit by approximately 20%.

There is high probability that a generator of this age that has not been operated for five years could have a major failure if it is started-up without being inspected and overhauled. Before using this machine, the generator should be dismantled, the rotor pulled, overall inspections done, and a full battery of insulation testing performed, including a reduced-voltage hi pot, electromagnetic core imperfection detection (ELCID), rotor winding imbalance, and other dielectric tests.

4.4.2.3 Major Concerns

The biggest cost item that could result from the testing of the generator would be the rewinding of the rotor and stator. Stator rewinds for hydrogen-cooled generators are usually required between the 30- and 40-year age of the machine. Rotor rewinds usually occur several years sooner.

Figure 4-4 — Stator Rewinds



Source: GE Energy, GER – 4223, January 2004.

Without testing the machines, the integrity of the insulation is not known; however, given the age and time of the last inspection, it is reasonable to expect insulation deterioration to the point that a rewind would be required.

Cracks in the rotor are often found in older machines. Surface cracking on the rotor near the ends where it most often occurs requires machining and possibly longer retaining rings.

4.4.2.4 Summary

To put these generators back into service in a reliable condition, the following costs would likely be incurred.

Table 4-7 — Estimated Costs for the Generators

Activity (includes both units)	Action	Estimated Cost
Disassembly & Testing: Insulation resistance and PI on both rotor & stator, pf tip-up, ELCID, reduced hi-pot, boroscopic, dye penetrant	Required	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Hydrogen Seals: Replace or repair H_2 seals	Required	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Rotor Repair: Tooth cracking, retaining rings, rewind	High Probability	Unit 1 $750,000 Unit 2 $750,000 Total $1,500,000
Stator Repair: Rewedge and rewind stator windings	High Probability	Unit 1 $1,250,000 Unit 2 $1,250,000 Total $2,500,000
Coolers: Clean and retube	High Probability	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Miscellaneous: Replace seal oil vacuum pumps Replace eroded valves	Required	Unit 1 $25,000 Unit 2 $25,000 Total $50,000
Total		$4,250,000

4.4.3 Switchgear and Motor Control Centers

4.4.3.1 Background

The voltage system for the motors and other auxiliaries in the plant is 480 volts, which is fed from the two General Electric 13.8–0.480-kV auxiliary transformers with a backup from the GE, 69–0.480-kV reserve auxiliary transformer. The 480-volt switchgear is indoor, metal-clad, and rated at 4,000 amperes at 600 volts. It was manufactured by the ITE Corporation, which is no longer in business, but replacements parts are still available from third-party suppliers.

Some of the original ITE switchgear on Unit 3 has had its breakers replaced with a Square D design. Switchgear lineups in Units 1 and 2 are still energized because they have feeder breakers that are still associated with equipment in Unit 3.

The Unit 1 and 2 motor control centers (MCCs) do not have disconnects that would allow them to be individually isolated, as is currently required by E.ON US engineering standards. The coal handling system that currently supplies Unit 3 was originally designed for Unit 1and 2 and was expanded when Unit 3 was later built. As a result, some of the coal handling system for Unit 3 is controlled through MCCs located on Units 1 and 2. Lighting and other common systems that are used throughout the plant are also partially powered from the Unit 1 and 2 MCCs. E.ON US engineering personnel told S&L that these MCCs that are common to Unit 3 will be eventually replaced with new MCCs that meet current engineering standards.

4.4.3.2 Return to Service

Based on the age of the switchgear that will have to be used in the operation of Units 1 and 2 if they are restarted, cleaning and refurbishment will be required for the switchgear to have it operate up to its specified level.

Since all of the MCCs will need to be replaced to meet current E.ON US engineering standards, the cost estimate is based on replacing all of the Unit 1 and 2 MCCs.

4.4.3.3 Major Concerns

There is a concern for spare and replacement parts for some of the equipment. That has not been a major problem in the past, but parts could become more of a problem due to lack of OEM or alternative suppliers.

4.4.3.4 Summary

The estimated cost of switchgear and MCCs replacement and overhauls are listed below.

Table 4-8 — Estimated Costs for Switchgear and MCCs

Activity (includes both units)	Action	Estimated Cost
Cleaning and refurbishment of the 480 volt switchgear	High probability	Unit 1 $20,000 Unit 2 $20,000 Total $40,000
Replace and reinstall the four condenser pit MCCs	Required	Unit 1 $75,000 Unit 2 $70,000 Total $145,000
Replace and reinstall the twelve boiler MCCs	Required	Unit 1 $30,000 Unit 2 $20,000 Total $50,000
Replace and reinstall the four turbine MCCs	Required	Unit 1 $20,000 Unit 2 $15,000 Total $35,000
Total		$270,000

4.4.4 Cable and Raceways

4.4.4.1 Background

Okonite provided the majority of the cables for Unit 1, and General Cable was the cable supplier for Unit 2.

4.4.4.2 Return to Service

Since the majority of the cables at Tyrone have not been in use for several years, they should be inspected and tested for loose connections and deteriorated insulation.

Insulation resistance should be measured using a megger, and the cables should receive a reduced hi-pot test at the rated voltage for each cable. The insulation shield on the underground cables connecting the generators to the main and auxiliary transformers should be checked for continuity and for proper grounding. During the unit startup program, thermographic surveys should be done to detect hot areas caused by connections that have become loosened over time.

Meggering and hi-potting the cables for both units would cost anywhere from $50,000 to $100,000, depending on the results.

4.4.4.3 Major Concerns

A cable failure on major equipment could bring the unit down. Failure of large cables that are routed underground between the generator and the main transformers in the switchyard would create one of the most serious consequences.

4.4.4.4 Summary

The estimated costs for cable and raceways are listed below.

Table 4-9 — Estimated Costs for Cables and Raceways

Activity (includes both units)	Action	Estimated Cost
Megger and hi-pot cables. Clean and tighten connections. Do thermographic survey	Required	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Replace and reinstall 1800 feet of single conductor, 15 kV cable	High probability	Unit 1 $20,000 Unit 2 $20,000 Total $40,000
Replace 3 phase, 1 kV power cable	High probability	Unit 1 $100,000 Unit 2 $100,000 Total $200,000
Replace control and instrument cable	High probability	Unit 1 $50,000 Unit 2 $50,000 Total $100,000
Total		$440,000

4.4.5 Motors

The major motors for the two units have not been operated for at least five years, so they will require cleaning and meggering before they are put back into service. The majority of these motors are open drip proof, so moisture accumulation in them could be a problem. If all the motors were inspected and checked out as usable, the cost of the inspection and cleaning would range between $50,000 and $100,000.

4.4.5.1 Summary

The estimated costs for motor inspections and overhauls are as follows.

Table 4-10 — Estimated Costs for Motor Inspections and Overhauls

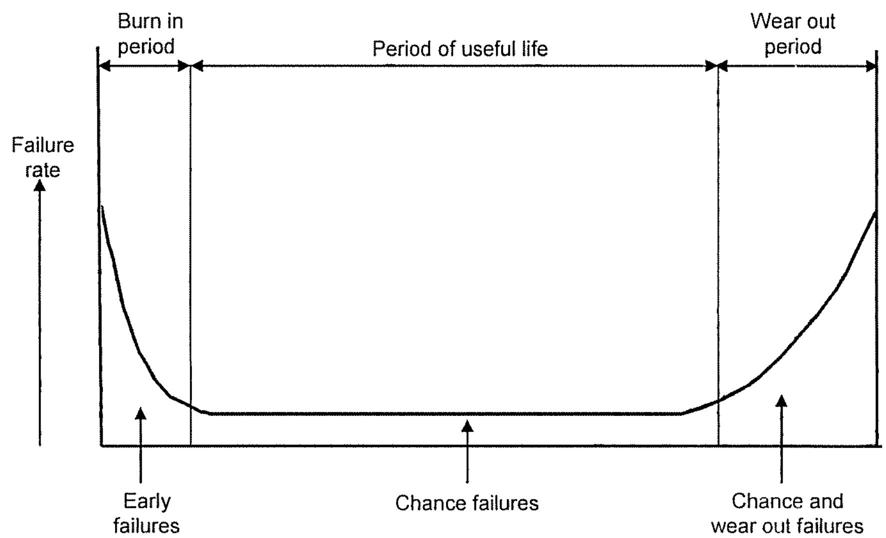
Activity (includes both units)	Action	Estimated Cost
Send out twenty two large, 460 volt motors on Unit 1for testing and cleaning Send out twenty large, 460 volt motors on Unit 2 for testing and cleaning	Required	Unit 1 $25,000 Unit 2 $20,000 Total $45,000
Inspect, megger and clean small 460 volt motors and dc motors	Required	Unit 1 $10,000 Unit 2 $10,000 Total $20,000
Total		$65,000

4.5 INSTRUMENTATION AND CONTROL SYSTEMS

4.5.1 Background

During the last 50 years, the instrumentation and control (I&C) systems evolved from the pneumatic in the 1950s, to analog in the 1960s, and finally to microprocessor-based and programmable logic controller (PLC) based systems beginning in the 1970s. The use of microprocessor-based or PLC-based depended on the type and scope of the application. Whenever a new generation of I&C systems is produced, spare parts of the preceding generations have limited availability and are expensive, if available. As such, many utilities have opted to replace I&C systems when they become obsolete. Another factor that affects the utility's decision is the life of the I&C systems. The typical mortality curve (Figure 4-5) for I&C system hardware indicates that their useful life is between 15 and 20 years. After that time, the hardware starts having high failure rates, which result in poor availability and high maintenance cost.

Figure 4-5 — Typical Mortality Curve for I&C System Hardware



4.5.2 Return to Service

The existing pneumatic systems for the boiler controls and monitoring are obsolete and have not been in service for a long time. It is likely that the many of the seals will need replacing and that internal controller parts will also need to be replaced. In many cases, these parts are not available from suppliers and must be manufactured in-house or through contracting to local machine shops. Therefore, to achieve the objective of returning the units to reliable service, the additions and/or upgrades discussed in the following subsections are recommended.

4.5.2.1 Boilers and Station Common Pneumatic Control System

The existing pneumatic systems for the boilers and station common should be replaced with PLC-based control systems. A total of three PLCs are recommended: one for Unit 1 boilers, one for Unit 2 boilers, and one for the station common (e.g., service water) systems. Each PLC would be provided with two central processing units (CPUs) and two power supply systems. Failure of any CPU and or power supply system would not cause the loss of the boilers and station common services control that are configured in the related PLC.

4.5.2.2 Field-Mounted Instruments

All field-mounted instruments used to provide the necessary indication for the units and station common services control and monitoring are recommended to be replaced. The new instruments would be electronic-type and would provide the 4-20 mA signals to the PLCs. Furthermore, because of the existing equipment age, it is recommended that all instrument tubing and valves between the instrument tap points and the instruments also be replaced.

4.5.2.3 Pump and Fan Motors and Motor-Operated Valves

The relay logic currently used for the control of pumps, fans, and the associated motors and for the motor-operated valves will be retained. However, the testing of the relay logic and the corresponding control switches and stations in the control room should be included in the commissioning and restart program.

4.5.2.4 Control Valves

The output signal from the PLCs to the control valves will be 4-to-20 mA dc. Therefore, electronic-to-pneumatic converters will be required for the interface with the PLCs.

4.5.2.5 FD Fan Inlet Vans

The pneumatic controller for the inlet vans of the four FD fan will be changed out to electric drives at a cost of $10,000 per fan.

4.5.2.6 Operator Interface

Three CRT-based operator stations are recommended for the boilers and station common services whose control logic is configured in the PLCs. The three stations would be configured such that each of them would have access to control any of the four boilers and the station common services. This configuration provides the necessary redundancy so that no one single failure would cause loss of access to the control of boilers and station common services.

4.5.3 Summary

The potential costs for returning the I&C systems to service are summarized in Table 4-11. These costs include the estimated installation costs.

Table 4-11 — Estimated Costs for Returning the I&C Systems to Service

Activity	Action	Estimated Cost
PLCs (Including the CRT-based Operator Stations)	Required	Unit 1 Boilers $120,000 Unit 2 Boilers $120,000 Station Common $80,000 Total $320,000
Field-Mounted Instruments (Based on 10 transmitters for each of the Unit 1 & 2 boilers and 15 transmitters for station common services)	Required	Unit 1 $40,000 Unit 2 $40,000 Station Common $60,000 Total $140,000
Control Valves Electric-to-Pneumatic Converters (Based on 6 control valves for each of the Unit 1 & 2 boilers and 10 control valves for station common services)	Required	Unit 1 $10,000 Unit 2 $10,000 Station Common $20,000 Total $40,000
FD Fan Control Drives	Required	Unit1 $10,000 Unit 2 $10,000 Total $20,000
Total		Unit 1 $180,000 Unit 2 $180,000 Station Common $160,000 Total $520,000

4.6 SAFETY EQUIPMENT

4.6.1 Fire Protection

To comply with National Fire Protection Association (NFPA) standards, it is recommended that fixed water-based fire protection be added to the following areas in the plant:

- Burner front for each boiler
- Turbine lube oil tank on each steam turbine
- Clean/dirty lube oil tanks

The estimated cost for a fire protection system is $250,000. The cost includes two new independent fire protection water supply pumps, as required by NFPA, and a fire protection control panel. Since the plant water supply system is not adequate for fire protection, a 250,000-gallon fire protection water storage tank (based on 2,000 gpm demand for two hours) will be required. The cost for the storage tank and interconnecting piping is estimated to be $500,000.

4.6.2 Burner Management Supervisory System

The Cohen Fyr-Monitor Supervisory Panel provides NFPA-code compliance for flame monitoring and burner operations that prevent furnace explosions. The pilot igniter proof-of-flame and the main fire flame scanner must be serviced and proven. Code-mandated trips and interlocks must be proven operational by exercising the related plant sensors to test the installed logic and wiring. In addition, OEM services may be required. The estimated expense for these activities is $80,000.

4.6.3 Summary

The estimated costs for safety equipment are summarized in Table 4-12.

Table 4-12 — Potential Costs for Safety Systems

Activity	Action	Estimated Cost
Install Fire Protection System per NFPA Standards	Potential	$750,000
Burner Management Maintenance	Required	$80,000
Total		$830,000

4.7 BALANCE-OF-PLANT SYSTEMS

4.7.1 Fuel Oil System

The existing fuel oil storage tank and underground piping is unlined and likely is not serviceable. The existing tank should be abandoned in place and replaced with a lined 500,000-gallon tank and above-ground piping. Replacing the tank and piping will require an $850,000 capital investment.

Oil guns and burner tips should be inspected and cleaned. Atomizing steam piping should be inspected and blown down with compressed air. Fuel oil and steam pressure regulating valves should be exercised and calibrated. Fuel oil pump mechanical seals should be inspected and reconditioned. The propane tank for the pilot igniters and the associated piping should be inspected for soundness.

Restoring the fuel oil system will require $20,000 per unit in expense.

4.7.2 Flue Gas System

Forced draft and induced draft fan rotors are prone to cracking at weld root lines. Sandblasting and NDE inspection for cracks should be performed. Cracks can usually be ground out and weld repaired. Testing and repair of the fans will cost $20,000 per unit.

Ductwork, expansion joints, the tubular air heaters including the internal expansion joints, and the abandoned hoppers associated with coal fly ash should be inspected for integrity and leakage. The estimated cost for inspection is $10,000 per unit. Based on the vintage of the units, there is a high probability a portion of the ductwork bracing and expansion joints will have to be replaced. An allocation of $70,000 per unit is included for the replacements.

Control and isolation vanes and dampers should be exercised and repaired as needed. An allocation of $5,000 per unit is included for minor repairs.

If the units are retired, the stack will have to have periodic inspections to verify structural integrity. In lieu of inspections, the stack can be removed. The estimated removal cost is $400,000, but the cost is dependent on the salvage value in effect at the time of removal. This cost is not included in the restart cost estimate.

4.7.3 Boiler Feed Pumps

Each unit has a motor-driven and a steam-turbine-driven boiler feed pump. Feed pumps have tight clearances at the impeller hub rings, and there is a danger that rust particles could accumulate in these tight spaces during extended shutdown. The pump casing should be opened, and the clearances measured and flushed if necessary. The shaft gear couplings must be cleaned and regreased to prevent seizure. If possible, suction strainers should be installed during initial startup.

Inspection and cleaning of the pumps will cost $10,000 per pump. Based on the vintage of the pumps, there is a high probability the pumps will need to be overhauled, at an estimated cost of $30,000 per pump.

The steam turbine drive must be opened for inspection at an estimated $20,000 expense. Based on the vintage of the steam turbine drive, there is a high probability that blade repairs and seal replacement are required, at an estimated cost of $50,000.

4.7.4 Other Rotating Equipment

Condensate, heater drain, and other low-pressure water pumps need to be drained and flushed, then repacked before operation.

The oil should be replaced in all equipment having bearing oil reservoirs, and all roller bearings should be greased before operation.

A sum of $30,000 should be allowed for inspection, repair, and lubrication of rotating equipment.

4.7.5 General

Before returning the plant to service, other activities associated with the plant equipment not previously discussed within this report will be required, the extent and cost of which will have to be evaluated. Based on the vintage of the units and the period of inactivity, certain equipment and components are suspect but, depending on the existing condition, will have to be evaluated case by case. Such equipment and components include the following

- Equipment gaskets and seals
- Instrument sensing lines
- Underground piping
- Stack and Liner

4.7.6 Summary

The estimated costs for balance-of-plant equipment are summarized in the following table.

Table 4-13 — Estimated Costs for Balance-of-Plant Systems

Activity	Action	Estimated Cost
Replace 500,000-gallon Storage Tank and Piping	Required	$850,000
Service Fuel Oil Firing Equipment	Required	Unit 1 $20,000 Unit 2 $20,000 $40,000
Flue Gas System Inspection*	Required	$25,000
Ductwork repairs and expansion joint replacements*	High Probability	Unit 1 $75,000 Unit 2 $75,000 $150,000
Control and isolation vanes and dampers repairs	High Probability	$10,000
FD and ID Fan Repairs	Required	Unit 1 $20,000 Unit 2 $20,000 $40,000
Boiler Feed Pump Inspections (3 pumps)	Required	$30,000
Turbine Drive Inspection	Required	$20,000
Miscellaneous Equipment Inspections	Required	$30,000
Boiler Feed Pumps Overhaul (3 pumps)	High Probability	$90,000
Turbine Drive Overhaul	High Probability	$50,000
Total Required and High Probability Items		$1,335,000

* Includes 10% cost adder for asbestos removal and disposal.

4.8 FACILITY AND EQUIPMENT SPARE PARTS

The infrequent operations of these units and the resulting long periods between major maintenance overhauls generally does not support a large inventory of spare parts beyond normal consumables and frequent maintenance items such as lubricants, chemicals, filters, and gaskets. A spare parts plan should be developed for these units if they are to remain in service. The plan should consider the use of available spare part inventories for Unit 3 and from other E.ON US generating units, as well as vendor supply programs. The I&C upgrades to PLC and digital field instrumentation will require some inventories of spare parts. The estimated costs for spare parts would be about $100,000.

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5. OPERATIONS AND TRAINING

The full-time plant staff at Tyrone has been significantly decreased from staffing levels of the 1970s when all three units were operated regularly. The current operating and maintenance staff is currently sized to meet the needs for operation of only Unit 3 and the common facilities required for operation of Unit 3. It is likely that additional operations and maintenance staff would be required to support operations of Units 1 and 2. In our discussions during the site visits, S&L was told that E.ON US would develop the staffing plans for Units 1 and 2. In developing the staffing plan, S&L recommends that E.ON US consider the potential reduction from previous staffing requirements for Units 1 and 2 if the I&C modifications described in Section 4.5 are implemented.

S&L was also told by E.ON US that many of the operators who had experience in the operations of Unit 1 and 2 have retired; therefore, a training program for the current operating staff would need to be conducted as part of the restart effort. As is generally done for startups of new generating units, the restart training program should begin with formal training sessions for the maintenance and operations staff. The objectives of this training would be to understand the purpose and function of each system and to understand proper operational and maintenance requirements of the equipment. Vendor support of this training will be required. In addition, adequate training of the new operators with the controls and instrumentation is essential. The operations staff would then provide operations support to the startup engineering team by operating the systems as they started-up and then operating the entire units through the startup testing. The startup team should include an operations supervisor with experience in operating units similar to Tyrone Units 1 and 2.

The restart of Units 1 and 2 should be managed similar to the startup of a new unit due to the many modifications and major maintenance activities. A formal startup plan should be developed that tests components individually and systems as a whole before first unit start. A startup team would consist of the plant staff that will operate and maintain the units along with experienced startup engineers. A process to turn over equipment from the control of the repair personnel to the control of operations would be established. Safety precautions are essential at all times during this turnover and startup of the systems. At some point of the startup timeline, it will be necessary to have the startup team working around the clock. Mechanical and electrical maintenance along with instrument technicians should be available with the operators on each shift during the startup to resolve problems.

The existing station startup procedures would be reviewed and revised by the startup team. The major changes to the procedures would be due to any I&C changes implemented. The sequence of events of the unit startup should be the same as before the renovation. In general terms, these steps would include the following:

- Establish and verify proper operation of auxiliary systems (i.e., compressed air, cooling water, fire protection, etc.)
- Establish and verify proper operation of feedwater / condensate/ circulating water systems
- Establish and verify proper operation of flue gas system
- Light off boiler and establish proper steam pressure and temperature
- Warm up and roll turbine
- Synchronize generator

The expense of the startup engineers would be an addition to the plant payroll costs. During the startup, it is expected that this shift will require two mechanics, two electricians, and one instrument mechanic. If the E.ON US staffing plan does not require this many permanent employees, additional costs will be incurred for contracted personnel during startup. The summary of costs for restart operations and training are listed in Table 5-1.

Table 5-1 — Estimated Costs for Restart Operations and Training

Activity	Estimated Cost
Startup Engineers (Planning, Training and Oversight)	$200,000
Vendor Training Support	$100,000
Total	$300,000

Last page of Section 5.

6. RETURN-TO-SERVICE ACTIVITIES

The following tables summarize the estimated costs for inspections, maintenance, overhauls, upgrades, replacements, and other costs as developed in Sections 4 and 5 of this report. The costs are delineated into the following categories:

- **Required Activities.** Required to provide for safe operations and to achieve the Performance Targets.
- **High Probability Activities.** Probably will be required, subject to inspections and testing.
- **Potential Activities.** Possibly required, given the age and condition of the unit equipment.

Table 6-1 — Required Return-to-Service Activities

Plant Systems	Unit 1	Unit 2	Common	Total
Boilers and Appurtenances	$265,000	$265,000	$0	$530,000
Steam Turbine and Appurtenances	$500,000	$500,000	$0	$1,000,000
Water Systems	$35,000	$35,000	$130,000	$200,000
Transformers and Breakers	$50,000	$50,000	$0	$100,000
Generators	$100,000	$100,000	$0	$200,000
Switchgear and MCCs	$125,000	$105,000	$0	$230,000
Cables and Raceways	$50,000	$50,000	$0	$100,000
Motors	$35,000	$30,000	$0	$65,000
Instrumentation and Controls	$180,000	$180,000	$160,000	$520,000
Safety Systems	$0	$0	$80,000	$80,000
Balance of Plant	$40,000	$40,000	$955,000	$1,035,000
Restart Operations and Training	$0	$0	$300,000	$300,000
Totals	$1,380,000	$1,355,000	$1,625,000	$4,360,000

Table 6-2 — High-Probability Return-to-Service Activities

Plant Systems	Unit 1	Unit 2	Common	Total
Boilers and Appurtenances	$435,000	$435,000	$0	$870,000
Steam Turbine and Appurtenances	$525,000	$690,000	$0	$1,215,000
Water Systems	$225,000	$225,000	$0	$450,000
Transformers and Breakers	$420,000	$65,000	$0	$485,000
Generators	$2,025,000	$2,025,000	$0	$4,050,000
Switchgear and MCCs	$20,000	$20,000	$0	$40,000
Cables and Raceways	$170,000	$170,000	$0	$340,000
Motors	$0	$0	$0	$0
Instrumentation and Controls	$0	$0	$0	$0
Safety Systems	$0	$0	$0	$0
Balance of Plant	$75,000	$75,000	$150,000	$300,000
Restart Operations and Training	$0	$0	$0	$0
Totals	$3,895,000	$3,705,000	$150,000	$7,750,000

Table 6-3 — Potential Return-to-Service Activities

Plant Systems	Unit 1	Unit 2	Common	Total
Boilers and Appurtenances	$0	$0	$0	$0
Steam Turbine and Appurtenances	$1,500,000	$1,500,000	$0	$3,000,000
Water Systems	$0	$0	$0	$0
Transformers and Breakers	$35,000	$250,000	$0	$285,000
Generators	$0	$0	$0	$0
Switchgear and MCCs	$0	$0	$0	$0
Cables and Raceways	$0	$0	$0	$0
Motors	$0	$0	$0	$0
Instrumentation and Controls	$0	$0	$0	$0
Safety Systems	$0	$0	$750,000	$750,000
Balance of Plant	$0	$0	$0	$0
Restart Operations and Training	$0	$0	$0	$0
Totals	$1,535,000	$1,750,000	$750,000	$4,035,000

A projected schedule to return the units to service is shown in Table 6-4. The Phase II schedule is dependent on the findings of the Phase I NDE testing and the extent of work required. Equipment delivery lead times will also affect the Phase II duration. The subsequent unit startup and testing will require an additional 4 to 6 weeks per unit.

Table 6-4 — Return to Service Schedule

Task	Start Week	End Week
Phase I – NDE Testing	1	17
Phase II – Overhauls, Repairs, Replacements	17	35
Phase III – Startup	34	44

Last page of Section 6.

7. MARKET VALUE OF EQUIPMENT

The resale value of the equipment at Tyrone is limited due to its age; nevertheless, there are sometimes buyers interested in vintage equipment if it meets a particular need they may have. Certain items such as the laminated steel core plates or copper windings of the generators and transformers have salvage value due to the high quality of the commodity. In addition, pulp mills and sugar refiners in South and Central America have been known to use older power plant equipment to operate their mills.

The integral arrangement of the three units as far as lighting and internal power distribution prevents the removal of some of the switchgear, MCCs, and housekeeping equipment. Steel contained in the stacks, boilers, and building structure will most likely have less value than its removal cost. For a power plant as old as Tyrone, large transformers and generators would have the best market value of equipment and commodities should the plant be retired. The following asset recovery estimate table was prepared for Tyrone:

Table 7-1 — Tyrone Asset Recovery Estimate

Equipment	Description	Estimated net tons	Scrap	Salvage	Re-use
Generator with exciter	Westinghouse 39,063 kVA, 30# H2, 13.8 kV, 3600 rpm	110	$22,000	$44,000	$77,000
Generator with exciter	Westinghouse 39,063 kVA, 30# H2, 13.8 kV, 3600 rpm	110	$22,000	$44,000	$77,000
Transformer, Main Power	3-phase, 13.8kV – 69 kV ≈ 30 MVA	40	$7,600	$19,000	$30,400
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Main Power	1-phase, 13.2 kV – 39.83 kV, 12.5 MVA	15	$3,000	$6,000	$10,000
Transformer, Aux Power	3-phase, 13.2 kV – 0.48 kV, 2.5 MVA	5	$1,000	$2,000	$3,500
Transformer, Aux Power	3-phase, 13.2 kV – 0.48 kV, 2.5 MVA	5	$1,000	$2,000	$3,500
Total		330	$65,600	$135,000	$233,400

Last page of Section 7.